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Western Interstate Energy Board
Final Report

RTG Resource Book for Western States and Provinces

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Prepared by the
Committee on Regional Electric Power Cooperation
and the
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Final Proceedings of Workshop on Formation of Regional Transmission Groups in the West

This constitutes the final report pursuant to Contract No. DE-FG02-93P010084. Under the contract, the Western Interstate Energy Board was to hold a workshop and liaison activities among western states, provinces and utilities on the formation of Regional Transmission Groups (RTGs). The purpose of these activities was to examine the policy implications for western states and provinces embodied in the formation of RTG(s) in the West, the implications for western ratepayers and utilities of the formation of RTGs and potential impacts of RTGs on the western electricity system. This was accomplished through: (1) the development of extensive background material and analysis; (2) the conduct of a workshop on October 20-21, 1993; (3) the preparation of a summary of the workshop; and (4) the execution of workshop follow-up activities, including participation in meetings held by western utilities and independent power producers to draft bylaws to form Regional Transmission Groups and providing information on those meetings to western states.

All of the major participants in RTG discussions in the West participated in the Regional Transmission Group Workshop including western states' Public Utility Commissioners and staff, governors' energy agencies, state facility siting agencies, the representatives from the provinces of British Columbia and Alberta, western utilities, independent power producers, the Department of Energy and the Federal Energy Regulatory Commission. Experts from the Wisconsin Public Service Commission and the Interregional Transmission Coordination Forum also participated.

The workshop contributed to fulfilling the transmission access and competition objectives of Title VII of the Energy Policy Act of 1992 by building a foundation for the creation of RTGs in the West and bringing together all the parties who will need to coordinate their activities to reach the objectives of the Act.

The contract proved to be very effective means of developing the level of trust and coordination needed among parties in the West for the successful development and implementation of RTGs.

The enclosed report includes a detailed summary of the October 20–21 RTG Workshop, a list of attendees at the workshop, background material prepared for the RTG discussion and information on the industry meetings attended by state representatives. There is also a copy of the side-by-side comparison of the bylaws of the four proposed western RTGs.

Western RTG Resource Book

The purpose of this book is to provide an easy to use, up-to-date source of information for western states and provinces on regional transmission group discussions in the West. The book is organized into three sections.

I. RTG Workshop

Briefing material for the October 20-21, 1993 workshop on western RTGs in Monterey, California.

II. Reports on Western RTG Developments

Reports and materials from future western industry RTG meetings. The Committee on Regional Electric Power Cooperation has been invited by western electric power industry to have a representative participate in these discussions. Regular meetings are expected to continue for the foreseeable future. You will be receiving information from these meetings.

III. Resource Documents

Included in this section are source documents on RTGs, such as FERC policies and rules and RTG bylaws. You will be sent updated copies of such documents.

Summary of the Western Regional Transmission Group Workshop

Monterey, California
October 20-21, 1993

October 20

The Chairman of the Committee on Regional Electric Power Cooperation, Bil Tucker, asked Jim Byrne (UT) to chair the workshop.

Byrne called the workshop to order. He noted that the formation of Regional Transmission Groups (RTGs) can further two interests of the states and provinces: (1) to improve the efficiency of the western electricity system; and (2) to keep important transmission planning and access decisions in the West and not in Washington, D.C.

Byrne thanked the Department of Energy for its support of the workshop and asked **Greg Basheda** from the DOE Office of Domestic and International Energy Policy to discuss the Department's views on RTGs. Basheda made several key points:

- The "consensus draft" considered in the Energy Policy Act (EPAct) debate on RTGs paid insufficient attention to the interaction of states and RTGs;

- DOE emphasized in its comments to the FERC on RTGs the need for timely resolution of technical issues, coordinated plans for transmission expansion (not piecemeal FERC transmission access orders) and pricing mechanisms to deal with loop flow; and

- Key questions involve state representation on RTGs, the degree of up-front state approval of RTG decisions, interaction and coordination between RTGs and utility integrated resource planning, and the role RTGs may play in any regional resource planning efforts.

Jim Byrne asked **Steve Herod**, Director of the Office of Electric Power Regulation at the Federal Energy Regulatory Commission, to review the recent actions the Commission has taken to enable the formation of RTGs. Herod reported that the FERC has acted with remarkable speed and that the new commissioners are moving in lock step toward promoting greater competition. The Commission has taken five key actions.

1. Exempt Wholesale Generators: Final rules are in place pursuant to the Energy Policy Act.

2. Transmission Information: The Commission has issued a final rule on information

utilities must file to allow the FERC to determine if it should order transmission access. The most controversial element in the rulemaking involved reporting of hourly system lambda data.

3. Good Faith Transmission Requests: The Commission has issued a policy statement establishing guidelines for "good faith" transmission requests and replies. Under the statement, network service may be requested. This issue, which was the most controversial, was raised by the Northern California Power Agency and other public power interests, and has caused some soul-searching at the Commission.

4. Transmission Access: Herod asked whether the Commission should issue more guidance on several non-price issues, such as mandatory access under Section 211 of the Federal Power Act and voluntary access using market based pricing and mergers. Herod noted that the authority to order access under Section 211 is broad based, but administrative implementation may be awkward and slow. Among the four access cases thus far, one was denied, one withdrawn, one (AEP) is in trial, and one (network service involving Florida Power & Light and the Florida Municipal Power Agency) is pending.

5. RTG Policy: The Commission has issued a policy statement on the elements of Regional Transmission Groups.

6. Transmission Pricing: The Commission has issued a notice of inquiry on the pricing of transmission services.

Questions were raised regarding wheeling on radial lines and Section 211 requests which, if granted, may transform a radial line into grid services. The policy is clear that one cannot secure transmission access on a radial line. One can, however, request an interconnection order under Section 210 (pre-EPAct) and thus turn a radial line into grid service. Question was raised about the treatment of Indian nations under the transmission access provisions of EPAct and the impact of access requests on existing contracts.

Herod made it clear that a Section 211 order will apply to both IOUs and municipal utilities. The Commission does not want to create two regulatory regimes, one under Section 211 and one under Section 205. Regarding network service, Herod said the Commission may deal with the issue in rulemaking.

Herod said it is not clear that Section 211 is working because it is not clear what is occurring in the industry. FERC Chair Elizabeth Moler declared Section 211 a success because there have been few requests for Section 211 orders. Herod it not sure if the full impact of Section 211 is clear yet.

Herod said there is not a great deal of collaboration between the Commission and PUCs on RTGs. NARUC is doing a paper on the issues, but Herod emphasized that the real action on RTGs is occurring in the West. He also said the Commission wants to see RTGs

formed. (Attachment A)

Alternative Approaches and Developments in Other Regions

To provide some perspective on western RTG discussion, two presentations were made on developments in other parts of the country.

Wisconsin: Mike Arny, with the University of Wisconsin and the Wisconsin PSC, discussed the Wisconsin approach to planning. A two-step process is used which requires that all transmission and generation additions must be approved in a resource planning proceeding before such facilities can be approved in a siting proceeding. Arny described the institutional setting in Wisconsin (two reliability councils, five IOUs, two joint action agencies and one G&T) and the steps in the transmission planning process. The objectives of transmission planning are to get only needed facilities built. With transmission corridors limited and siting difficult, the state does not want to squander goodwill by building transmission that is not necessary. He noted the need to have decision information available to all interested parties. Wisconsin provided funding for intervenors through the utilities, which was important in initial planning efforts. Intervenors are not regular participants in planning now. The state also required utilities to develop more than one solution to each transmission problem.

The role of the PSC staff in transmission planning was to make sure that information that will be needed in a Commission decision is developed during the planning process. To do this staff needs to participate in the planning process, develop criteria for analysis, and include environmental reviews early in the planning process.

In 1989, the PSC ordered the state's utilities to file wheeling tariffs with FERC. This was because the state does not have the authority to review tariffs and FERC lacks the authority to order filings. Utilities, which all made the required filings, appealed the state's order to file with FERC, but the Commission has not acted. The utilities also took the state to court, but the court decided the issue was moot. Wisconsin has the authority to order ownership of new and existing transmission lines.

Arny argued that the Wisconsin experience suggests that RTGs need to prepare information for state siting and need determination decisions. He noted that the value of the Wisconsin approach would be enhanced if its geography extended beyond the borders of the state. By mutual agreement among states and other governmental organizations, such information should be at a high enough level to meet the needs of all affected governmental organizations. (Attachment B)

Interregional Transmission Coordination Forum (ITCF): Bob Arnold, Executive Vice President for Power Supply at GPU Service Corp. and Chairperson of the ITCF, discussed the goals of the ITCF, which are to promote coordination, resolve disputes through voluntary mediation, and resolve parallel path issues. The parallel path issue drove much of the interest

in closer coordination. The effort evolved out of a long period of voluntary local and regional cooperation among utilities. The loss of Three Mile Island caused PJM utilities to find cheaper power outside the power pool. This resulted in loaded tie lines between the PJM region and other areas. ITCF was initiated in 1990 and included participation of key utility executives that could quickly resolve transmission issues. A wide range of companies now belong to the ITCF from Maine to Louisiana. Ontario hydro participates but did not join the Forum because of concerns about being subject to FERC jurisdiction.

The ITCF filed with the FERC to alleviate anti-trust concerns. FERC accepted the filing, but noted that the ITCF does not constitute an RTG because it does not meet the requirements in FERC's RTG policy statement (e.g., the ITCF does not mention how it will coordinate with state regulatory and other authorities, it does not obligate members to provide transmission service, its geography is not efficient or sufficiently contiguous, it does not provide for a coordinated plan to meet reliability and economic demands on the transmission system). Arnold noted that the ITCF was not currently seeking RTG status and the formation of the ITCF does not preclude the formation of subregional RTGs.

Arnold reviewed the General Agreement on Parallel Paths (GAPP) mission statement which is to explore the practicability of replacing the single contract path approach with a multiple contract path approach such that the transmission systems which are impacted by specific transactions are appropriately involved from a contacting, schedule and operations perspective. A discussion paper is to be prepared for the ITCF which compares the current single contract path approach to the implications of multiple contract paths. (Attachment C)

Steve Herod (FERC) said the ITCF was a big step forward before EPAct, but now the Commission views RTGs as a better alternative. Floyd Hammerquist (PacifiCorp) cited the loop flow issues in the West and efforts to coordinate phase shifter operations and curtailments as examples of WSCC dealing with economic issues in the western system. Action on loop flow is expected by the WSCC by the end of the year and there will be a rate schedule filing with the FERC that will require the Commission to act. Bil Tucker (WY) argued that the Committee on Regional Electric Power Cooperation should consider supporting such an application to the FERC. Bill Martin (Colorado Public Service), who chairs the WSCC's Regional Planning Policy Committee, emphasized the need for early input into transmission planning.

Transmission Pricing

Steve Herod reviewed the evolution of FERC's transmission pricing policies — from 1) the traditional postage stamp approach, to 2) the current "and/or" issue and "lesser of" issue to 3) the Commission's inquiry into potential transmission pricing reforms. (Attachment D) He emphasized that all the pricing policy options, including those being considered in the pricing inquiry are cost-based. However, the options can change the allocation of revenues. The FERC's approach covers costs at the wholesale level and PUC decisions are to cover costs at the retail level. The current pricing policies have been endorsed by the "old"

Commission and the current Commission.

In discussion it was argued that the transmission grid has all sorts of barriers which may make "and/or" pricing inappropriate. Herod noted that "and/or" pricing made sense in the context of the fictional contract path approach, but when moving to a contract path or megawatt-mile approach "and/or" pricing may not make sense. A question was raised about the difficulty of a small utility responding to a transmission request requiring a very expensive upgrade. Roger Fontes (NCPA) noted that WATSCO dealt with the difficulty of raising capital for expansion by allowing the requestor to pay for the addition and granting ownership or "ownership-like" rights in the upgrade. Herod noted that the requestor would not receive ownership rights.

Herod said that the FERC is unlikely to definitive on pricing issues and it would likely be decided on a case-by-case basis. He argued that the sequencing of pricing and RTG decisions may be important; that is, it may be appropriate to develop an RTG first and then allow the RTG to set pricing policies. Fontes noted that the transmission pricing inquiry is not having a chilling effect on RTG formation. Harlow Peterson (SRP) reported that SWRTA has put pricing issues aside on the grounds that the FERC will set pricing policy. Jim Kritikson (SCE) said that the attorneys are concerned about utilities dealing with pricing because of anti-trust concerns. An option may be to have the seller propose a pricing scheme and have the RTG dispute resolution process resolve it and the FERC defer to the RTG decision. Chris Ellison, Independent Energy Producers (IEP) argued that too much emphasis is placed on RTGs resolving pricing and other issues. He suggested that the FERC and the states need to define the alternative to an RTG and then let potential RTG participants decide if they should join. Herod stated that as long as IPPs are included in RTGs that there is no anti-trust problem. Steve Walton (PacifiCorp) suggested that there is a need to allow RTGs and pricing issues to evolve over time. Allan Vallow (LADWP) noted that there are a number of participants in the WATSCO discussions that do not want RTGs establishing transmission pricing schemes even if the FERC determines such schemes are just and reasonable. He noted that there is always the option to apply for a new transmission pricing scheme under Section 205 of the Federal Power Act. Jim Byrne (UT) closed the discussion by advising the states and provinces that they will be discussing potential collective responses to the FERC's transmission pricing inquiry later in the meeting.

Overview of Western RTG Issues

Steve Walton (PacifiCorp), who has been coordinating **west-wide RTG discussions,** provided an overview of the major issues. The FERC's notice of inquiry on the "consensus agreement," which was debated as part of last year's Energy Policy Act, was the impetus for the west-wide discussions. Bylaws have been drafted for a west-wide group and are the subject of continuing meetings. Walton outlined the major issues: the linkage between any west-wide RTG and subregional RTGs; development of a contract or constitutional approach to forming an RTG; association governance (including obligations upon withdrawal from the RTG); state and provincial government participation in an RTG; resolving requests for

transmission service; dispute resolution (including the ability of the Western Area Power Administration and the Bonneville Power Administration to enter into binding arbitration); the nature of dispute resolution, including whether arbitration awards set a precedent; planning, particularly the role of the WSCC; and transmission pricing. Walton particularly asked the states/provinces to provide advice on the role PUCs and energy agencies should play in RTGs. He argued that if a central transmission plan (as opposed to coordinated planning) is required by FERC, there will be no RTGs formed in the West. (Attachment E)

Harlow Peterson (SRP) reported on the **Southwest Regional Transmission Association**, noting that discussions have been under way for the past year and one-half and that over the course of that time the number of participants in the discussions has doubled. Since April, the discussions have included smaller IPPs, municipal utilities and some new IOUs. Bylaws are close to being finalized. It is hoped that the bylaws will be completed by December. Thereafter, two months would be allotted for organizations to approve the bylaws and they would be filed with the FERC in the first quarter of 1994. Discussions will be held with the states of Arizona, Nevada, New Mexico, Texas and Utah and those states will be asked how they want to participate in SWRTA. Meetings will also be held with the FERC and FERC staff. SWRTA's geography will be decided by those who joins the organization.

Roger Fontes (NCPA) reported on efforts to form a **Western Association for Transmission Systems Coordination (WATSCO)**. In March, bylaws were completed, however, participants did not approve the bylaws. SCE and LADWP are now engaged in delicate negotiations to redraft the bylaws to be more acceptable. Fontes dispelled several myths about WATSCO, including that WATSCO is too onerous (in fact, the NCPA/PG&E transmission deal is tougher on PG&E than WATSCO); states are cut out of WATSCO (in fact, the WATSCO concept began in response to ideas generated at a California Energy Commission proceeding and ex-officio state membership has been allowed and extended to the WATSCO Planning Committee); transmission access puts native load customers at risk (in fact, native load customers are held harmless); and WATSCO is "anti-WSCC" (in fact, WATSCO grandfathers in WSCC reliability criteria, uses the WSCC data base where possible, and encourages all WATSCO members to join WSCC). Fontes urged the states to let utility vice presidents and CEOs know of the states' interest in RTGs. Fontes believes that the future without RTGs is draconian, with such things as new laws on eminent domain and common carrier requirements.

Floyd Hammerquist (PacifiCorp) reported on RTG discussions in the **Northwest**. He reported on a pre-"consensus draft" meeting with IOUs and public utilities and the subsequent invitation to IPPs and Canadian utilities to join the discussions. There has been general agreement on principles and issue papers have been drafted recently. He noted that there are some unique issues in the Northwest, such as reservation of transmission capacity for non-firm power to avoid spilling of hydro. The Northwest discussions are currently on hold, pending the outcome of the west-wide discussions. If a west-wide RTG is formed, many Northwest parties will join that RTG; if no west-wide RTG is formed, the Northwest discussions will proceed.

Bill Martin (Colorado Public Service Company) reported on the transmission discussions in **Colorado and eastern Wyoming**. He made clear that the principles agreed to by two IOUs, 30 municipalities, 20 cooperatives and three G&Ts in the area do not constitute an RTG and that there is no intent to form an RTG. The agreement grew out of a threat by Colorado municipal utilities to block the acquisition of the assets of the bankrupt Colorado Ute Electric Association by PSCo, PacifiCorp, and Tri-State G&T. The municipal utilities wanted to preserve access to the Ute transmission system. The principles deal with pricing, planning and dispute resolution. IPPs are welcome to sign the principles. Martin said the agreement is not an RTG because planning must be done on a larger scale (e.g., west-wide). He argued that an RTG should be as big in geography as possible. He recognized the challenges of dealing with localized problems, but said that one does not need an RTG to deal with such problems.

Regional/Subregional RTGs

Jim Byrne (UT) introduced the issue of forming one regional and/or subregional RTGs in the West, or some type of hybrid RTG. He noted the need to avoid creating seams in the western system and asked the industry participants to highlight the regional/subregional issues.

Allan Vallow (LADWP) acknowledged that regional RTGs and regional planning are the ideal, but he does not believe that the west-wide agreement is achievable. For example, the access issues in California are different given the multitude of transmission dependent utilities. Therefore, there is a need to move at the subregional level. Vallow suggested that access may need to be dealt with by a subregional organization and planning by the WSCC. However, he noted that smaller parties are not adequately represented in WSCC processes. Dick Casad (WA) noted that in the Northwest access issues almost always involve BPA because of its transmission ownership. Bill Martin (PSCo) argued that the bulk of planning is already occurring at the regional level under the WSCC. Floyd Hammerquist (PacifiCorp) reported that there is a vacuum of planning at the subregional level in the Northwest. A meeting is set for October 26 to begin subregional planning discussions in the Northwest.

Bob Mooney (Idaho Independent Energy Council) said that IPPs prefer a west-wide RTG, but if subregional RTGs are formed there is a need for inter-RTG compatibility. Jim Kritikson (SCE) reported that the California Power Pool does not do planning and that the WATSCO bylaws were drafted to accommodate a California-specific appendix to reflect local conditions. He noted that the west-wide bylaws do not deal with transmission set asides to accommodate bidding, but that this is dealt with in the WATSCO approach. Chris Ellison (IEP) noted that subregional RTGs disagree on key issues, such as how arbitration should operate. However, he sees an underlying "seams" issue with subregional RTGs. He also suggested that there is a convergence of west-wide and subregional RTG approaches in the on-going west-wide RTG discussions. Kashi Mattu (POWEREX) argued that real regional differences (e.g., transmission to avoid hydro spill) must be the basis of any subregional RTGs. She said POWEREX prefers a west-wide RTG because of the character of power markets.

Harlow Peterson (SRP) argued that 80 percent of the issues to be dealt with by an RTG are subregional issues and only 20 percent are west-wide issues. He noted that it is easier to build consensus among smaller groups and said that Southwest IPPs favor a subregional approach because their business is local and they do not want to join a west-wide RTG. Steve Walton (PacifiCorp) is concerned that the creation of subregional RTGs will result in those entities taking on an identity of their own and it will be difficult to merge subregional RTGs in the future. Denise Mullen (BC) questioned whether the U.S./Canada Free Trade Agreement would preclude Canadian parties from withdrawing from any type of RTG.

Transmission Planning

Dennis Eyre (WSCC) set the stage for a discussion of transmission planning by RTGs by reviewing how transmission planning has been done historically and how it is evolving under the WSCC's Regional Planning Policy Committee. A new force affecting planning is competition. He noted that WSCC is ahead of most reliability councils in that its membership is open to all parties, including IPPs, and that WSCC allows access to its data sets. In November, two WSCC executive committee members will be IPPs or exempt wholesale generators.

Steve Herod (FERC) asked about the focus of planning, noting that NERC's planning focus is on reliability and does not include economic efficiency. Eyre stated that last year WSCC adopted a transmission line rating process. Under the process, the rating of existing facilities is grandfathered, however, new facilities are required to preserve the ratings of existing facilities. Harlow Peterson (SRP) discussed the WSCC project rating process (see table in briefing book), and argued that the Southwest Intertie Project (SWIP) has gone a long way to putting the new WSCC process in place. Dennis Eyre discussed the Western Loads and Resources Study which grew out of the SWIP discussions. PacifiCorp volunteered its modeling data base to SWIP which has been assemblying a more comprehensive data base. The hope is that utilities participating in the study will transfer their data base to WSCC and that the resulting data and model will be an important tool in regional planning. (Attachment F)

Workshop chairman Byrne opened the discussion of the role of the WSCC in RTGs. Roger Fontes (NCPA) noted that there are about 60 members of WSCC, far fewer than the 200 potential members of RTGs. He said fundamental changes are needed at WSCC to make it an RTG. He argued that transmission issues are contentious and noted that coordination activities in places such as the Colorado/Wyoming area are the result of the merger sledgehammer.

Bob Arnold (ITCF) said in the East state regulators are involved in decisions much later in the planning and implementation process than what is being discussed in the West. Otherwise many of the activities in the New York/PJM areas are similar to the WSCC planning activities, except that non-transmission owners do not participate early in the

process. In the East, there is discussion of whether regional reliability councils can do more than reliability issues. The ability to cross over from reliability to economic and access issues is not clear. However, eastern councils are beginning to broaden their membership. Mike Arny (WI) noted there is little RTG activity in the MAIN or MAPP regions, however, MAPP is starting to think about an RTG, but it may be a long-term process. MAPP is already a powerpool as well as a reliability council.

Bob Mooney (IIEC) said his group is willing to work with the WSCC to make the transition to an acceptable RTG organization. Non-utility suppliers have not traditionally participated in WSCC, but he believes that is a matter of education of the IPPs on the WSCC and how to participate.

October 21

Jim Byrne reconvened the meeting to discuss several other outstanding topics, including the role of Power Marketing Administrations in RTGs, the role of Canadian utilities and to continue the discussions from the previous day, particularly the role of the WSCC in RTGs.

Role of Federal Power Marketing Administrations

Lloyd Greiner (WAPA) reported on the views of the Western Area Power Administration on RTGs. WAPA prefers a west-wide RTG under the WSCC umbrella, but could support a stand-alone west-wide RTG. He noted that WAPA has not joined the Colorado/Wyoming discussion group and has not been active in SWRTA and WATSCO. WAPA's major concern is the use of binding arbitration which the agency is not able to agree to. However, WAPA is asking the Justice Department for their views on WAPA's ability to agree to binding arbitration. It is also unclear if WAPA can abide by an order to construct a new transmission facility, because the agency is subject to Congressional appropriation. Further, WAPA must have Congressional authorization even to accept funds from other parties.

Steve Walton (PacifiCorp) noted that BPA has been leading RTG discussions in the Northwest and been active in west-wide discussions. (BPA was unable to attend the workshop.) He noted that BPA prefers a west-wide RTG. BPA believes that if the Department of Justice agrees that FERC judgments are final federal agency decisions, then BPA can submit to binding arbitration under the law. Larry Ingram (NM) pressed for WAPA to be bound by RTG discussions like other parties. Dick Casad (WA) said that unless BPA can participate in an RTG on equal terms with other parties, it will be difficult to form effective RTGs. Steve Walton and Roger Fontes disagreed noting that WAPA's inability to abide by binding arbitration is parallel to the authorities retained by state regulatory bodies and city councils. In response to a question, Walton added that BPA membership in an RTG is a step in the right direction to making BPA an equal player. Walton also noted that the trend at BPA and the FERC to approach transmission as unbundled services has not been a

problem so far in RTG discussions.

Role of Canadian Parties

Kashi Mattu (POWEREX) argued that Canadian industry participation in an RTG will enhance competition and increase efficiency. She noted that many of the issues she is raising are shared by TransAlta and Edmonton Power in Alberta.

Mattu reported that Canadian jurisdiction is not parallel to that in the U.S. in that the National Energy Board (NEB) does not have the authority the FERC possesses. The NEB is looking at interregional regulation, but utilities do not want the NEB's authority extended and urge that the decisions be left to the provinces. She noted that in July 1992, B.C. endorsed a long-term export policy and approved retail wheeling for transactions less than one year. She also said that Alberta is moving toward increasingly open electricity markets.

Regarding RTGs, POWEREX does not want to see their boundaries limited to the international border. She asked if Canadian utilities could request a Section 211 order. Steve Herod (FERC) did not believe that Canadian utilities can make a Section 211 request,. however, the buyer of Canadian power can ask for a Section 211 order. Mattu also asked if participation in an RTG subjects Canadian utilities to U.S. law, particularly at the dispute resolution stage. He noted that these international issues are not new, that there are already international pooling arrangements and that Canadian parties should be able to fully participate in RTGs.

Mattu noted the concern Canadian parties have about FERC jurisdiction and cited the language in the draft west-wide RTG bylaws which provides that Canada will provide "no less favorable" treatment than would be provided by the FERC. This is the approach taken in the U.S./Canada Free Trade Agreement. She suggested that transboundary disputes be resolved by a non-U.S., non-Canadian regulatory body.

Regarding the power marketing administrations, she urged that FERC's policies align the PMAs commercial activities to comport with those of other activities. She urged true reciprocity for BPA and discouraged special rules. POWEREX wants FERC to construe the BPA-specific language in the Free Trade Agreement very narrowly and noted that POWEREX has intervened at the FERC on BPA transmission rates.

She concluded that: POWEREX prefers a west-wide RTG; RTGs should provide timely responses to requests for service; and if Canadian parties are unable to participate in access and dispute resolution, they should at least be able to participate in RTG planning activities.

Denise Mullen-Dalmer (BC) reported that the provincial government's transmission policy is to first consider domestic market needs and then consider transmission to support exports. Roger Fontes asked what pricing scheme (embedded or opportunity cost) is used.

Mattu responded that that determination is made on a case-by-case basis.

Jim Byrne asked Steve Herod about the time needed for FERC to respond to Section 211 requests. Herod noted there is little evidence thus far, but estimated it may take nine months, but that will change depending on the number of transmission requests received.

Dick Casad (WA) concluded that it is possible to create a workable RTG with Canadian participation and that such participation should not negatively affect Canadian sovereignty.

State and Provincial Roles in RTGs

Workshop Chairman Jim Byrne asked for views on the appropriate role for states and provinces in RTGs and noted that the west-wide draft bylaws have provisions for states/provinces to be non-voting, ex-officio members. Steve Walton (PacifiCorp) said he envisions states expressing their views at RTG meetings, not just operating as a liaison. Jim Byrne noted this could be difficult on some issues. Dick Casad (WA) supported the proposal that states/provinces should be non-voting participants, but emphasized the need to have access to information and participate in discussions. Jim Kritikson (SCE) reported that the WATSCO bylaws allows interested parties (e.g., states) to intervene in arbitration processes. Mary McKenzie (CA) expressed the interest in states preserving their regulatory authority to protect consumers regardless of the role states play in RTGs.

Bob Anderson (MT) argued that RTGs should not do planning; that should be left to state IRP processes and the WSCC. He liked the concept of state non-voting membership in RTGs to allow information to flow in both directions. He also said there is need for a formal way for the states' ex-officio members to share information with their colleagues, possibly through the Committee on Regional Electric Power Cooperation. Byrne suggested that the Department of Energy should have an interest in supporting state participation in RTGs.

Steve Herod (FERC) believes that WSCC's planning initiative meets the objectives of FERC's RTG policy statement and that there is nothing comparable in the East. Mike Arny (WI) argued that states need to decide on what objectives they have in participating in an RTG. For example, are RTGs the way regulators can get answers to their questions regarding planning? Are RTGs the way in which states can bring IRP results to regional planning? He suggested that funding of state participation be considered in much the same way as Wisconsin has funded intervenor representation, possibly directing funds through a regional organization to minimize the appearance of utility influence over state decisions.

Jim Byrne asked if states should seek to have both commissioner and staff representation at RTG meetings. Harlow Peterson (SRP) said he wants state involvement up front and to accomplish this states need background information before the decisions reach regulators. Phil Carver (OR) argued for a state role in technical planning issues either through participation by each state, by designated state technical representatives or by WIEB

staff participation, and urged that DOE consider financially supporting such technical work. Larry Ingram (NM) agreed with Anderson and Casad, but expressed concerns about ex-parte problems even with ex-officio membership, and thus was inclined to use staff as a proxy for commissioners at RTG meetings. JoAnne Kelly (NV) expressed support for RTG development and noted its importance in the area of power purchase contracts. John Mendoza (NV) reported that the Nevada commission has not discussed state representation in RTGs yet.

Roger Hamilton (OR) argued that IRP is done utility by utility and that there is a need for a mechanism to integrate IRP results and regional transmission planning. He suggested this as an important topic for a future meeting. Dick Watson (NWPPC) said the Northwest Power Plan does not address transmission planning. Judy Lamson (WA) cited the linkage between coordination and planning and the increasing role of bidding for new resources and suggested this as an agenda item for the next meeting of the committee on Regional Electric Power Cooperation.

State/Provincial Discussions

Jim Byrne surveyed states on whether they were intending to submit comments to the FERC on the Commission transmission pricing inquiry. The Idaho PUC has filed comments, the Washington State Energy Office is developing comments, the California PUC and CEC are developing comments and Nevada and Arizona were hoping to prepare comments. Byrne distributed a draft set of comments prepared by the WIEB staff based on the discussions of the previous day. Byrne asked for comments on the draft. Several editorial comments were suggested.

Larry Ingram (NM) asked Steve Herod about the use of Joint Boards in conjunction with the FERC's review of proposed RTGs. Steve Herod (FERC) argued that evidence is needed that Joint Boards can contribute to effective issue resolution and suggested that workshops, such as this one, are a more effective means of dealing with RTG issues than Joint Boards.

Jack Haenichen (AZ) moved and JoAnne Kelly (NV) seconded a motion to forward the proposed comments on transmission pricing to the Committee on Regional Electric Power Cooperation for adoption. Motion was adopted. Byrne said the Committee on Regional Electric Power Cooperation would consider the comments at its meeting the following day. (See Tab 3 D in *Western RTG Resource Book* for text of final Committee comments to the FERC.)

Bob Anderson (MT) reported for Christine Alvarez (CO) on a proposed meeting of regulators from Wyoming, Colorado, Arizona, New Mexico and Utah to discuss the role of regulators in RTGs. Dick Casad (WA) and Bil Tucker (WY) noted that such a meeting is not a meeting of a subset of the Committee on Regional Electric Power Cooperation and urged that such discussions take place within the Committee.

Phil Carver (OR) urged that technical people in the states/provinces be linked with WSCC planning people in much the same was as policy-level discussions are occurring between the states/provinces and utilities at the meetings of the Committee on Regional Electric Power ooperation. Jim Byrne suggested this as a topic for the next CREPC meeting. Jim Byrne then adjourned the workshop.

Western Interstate Energy Board
Committee on Regional Electric Power Cooperation
October 21-22, 1993
Monterey, California

Name	Organization	Address	Phone
Larry Charach	Alberta Energy Dept.	9945 108th St. Edmonton, Alberta Canada T5K 2G6	403/427-8177
Jack Haenichen	Arizona Energy Office	3800 N. Central Ave. Suite 1200 Phoenix, AZ 85012	602/280-1403
Denise Mullen-Dalmer	B.C. Ministry of Energy, Mines and Petroleum Resources	1810 Blanshard St., 7th Floor Victoria, British Columbia Canada V8V 1X4	604/952-0264
Daniel Nix	California Energy Commission	1516 Ninth Street Sacramento, CA 95814	916/654-4861
Bill Chamberlain	California Energy Commission	1516 Ninth Street Sacramento, CA 95814	916/654-3951
John Wilson	California Energy Commission	1516 Ninth Street Sacramento, CA 95814	916/654-5056
Eric Wong	California Energy Commission	1516 Ninth Street Sacramento, CA 95814	916/654-3992
Al Alvarado	California Energy Commission	1516 Ninth Street Sacramento, CA 95814	916/654-4749
Dan Fessler	California PUC	505 Van Ness Ave. San Francisco, CA 94102	415/703-3491

Name	Organization	Address	Phone
Kent Wheatland	California PUC	505 Van Ness Ave. San Francisco, CA 94102	415/703-1825
Barbara Hale	California PUC	505 Van Ness Ave. San Francisco, CA 94102	415/703-3491
Mary McKenzie	California PUC	505 Van Ness Ave. San Francisco, CA 94102	415/703-2760
Marsha Smith	Idaho PUC	Statehouse Mail Boise, ID 83720	208/334-3912
Tom Faull	Idaho PUC	Statehouse Mail Boise, ID 83720	208/334-0351
Chuck Durick	Idaho Power Company	P.O. Box 70 Boise, ID 83707	208/383-2450
Bob Anderson	Montana PSC	1701 Prospect Helena, MT 59620	406/444-6199
Larry Nordell	Montana DNRC	1520 E. Sixth Helena, MT 59620	406/444-6757
Jo Ann Kelly	Nevada PSC	4041 S. Spenser #A44 Las Vegas, NV89158	702/486-6550
R. Prasad Potturi	New Mexico PUC	224 E. Palace Ave. Santa Fe, NM 87501-2013	505/827-6977
Phil Carver	Oregon Dept. of Energy	625 Marion St. N.E. Salem, OR 97310	503/378-6874

Name	Organization	Address	Phone
Roger Hamilton	Oregon PUC	550 Capitol St. N.E. Salem, OR 97310	503/378-6611
Sarah Cleveland	Oregon PUC	550 Capitol St. N.E. Salem, OR 97310	503/378-3217
Rebecca Wilson	Utah Dept. of Energy and Resource Planning	3 Triad Center Suite 450 Salt Lake City, UT 84180-1204	801/538-5428
Jim Byrne	Utah PSC	Box 45585 Salt Lake City, UT 84145	801/530-6716
Jim Harding	Washington State Energy Office	809 Plum Street. P.O. Box 43165 Olympia, WA 98504	206/956-2007
Ken Elgin	Washington UTC	P.O. Box 47250 Olympia, WA 98504	206/586-4510
Judy Lamson	Washington UTC	P.O. Box 47250 Olympia, WA 98504	206/586-1186
Dick Casad	Washington UTC	P.O. Box 47250 Olympia, WA 98504	206/753-6440
Bil Tucker	Wyoming PSC	700 W. 21st Street Cheyenne, WY 82002	307/777-7427
Doug Larson	WIEB	600 17th Street Suite 1704 South Denver, CO 80202	303/573-8910
Greg Basheda	U.S. DOE	1000 Independence Ave. Washington, D.C. 20585	202/586-4871

Name	Organization	Address	Phone
Steve Herod	FERC	825 N. Capitol St. N.E. Washington, D.C. 20426	202/208-1200
Jim Miernyk	WIEB	600 17th Street 1704 South Tower Denver, CO 80202	303/573-8910
Dick Watson	Northwest Power Planning Council	851 S.W. 6th Ave. Suite 1100 Portland, OR 97204	503/222-5161
Jim Macias	Pacific Gas & Electric Company	123 Mission St, San Francicsco, CA 94106	415/973-1441
Barry Solomon	U.S. EPA	401 M Street S.W. 6204J Washington, D.C. 20460	202/233-9166
Cathy Ghandehari	U.S. DOE	Denver Support Office 2801 Youngfield St. #380 Golden, CO 80401	303/231-5750

ATTACHMENTS

The following attachments were handed out at the RTG workshop and are not included in this mailing to attendees of the workshop. If did not receive a copy of any of the following documents and want one, please call WIEB staff (303\573-8910).

Attachment A:	"Status of FERC's Implementation of the Energy Policy Act," J. Steven Herod
Attachment B:	Wisconsin Planning Process, Mike Amy (handwritten)
Attachment C:	"The Committee on Regional Electric Power cooperation and the Western Interstate Energy Board Workshop on Regional Transmission Associations," Robert C. Arnold **(Suggest it be filed behind Tab 3 G in *Western RTG Resource Book*)**
Attachment D:	"An Overview of Transmission Pricing Issues," J. Steven Herod **(Suggest it be filed behind Tab 3 D in *Western RTG Resource Book*)**
Attachment E:	"An Overview of RTG Issues"
Attachment F:	Western Systems Coordinating Council

Finally, the gold pages are a correction to the gold pages found behind **Tab 1 in the *Western RTG Resource Book.***

STATUS OF FERC'S IMPLEMENTATION OF THE ENERGY POLICY ACT[1]

J. STEVEN HEROD
DIRECTOR OFFICE OF ELECTRIC POWER REGULATION
FEDERAL ENERGY REGULATORY COMMISSION

Presentation To:
Western Interstate Energy Board
Monterey, California

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[1] *The analyses and conclusions are those of the author and do not necessarily reflect the views of the Federal Energy Regulatory Commission, any individual Commissioner or any other staff member.*

Major Elements

1. *Certification of EWGs (Rule)*
2. *Transmission Information (Rule)*
3. *Good Faith Request/Response (Policy Statement)*
4. *Transmission Access*
5. *Regional Transmission Groups (Policy Statement)*
6. *Transmission Pricing (Inquiry)*

Certification Of Exempt Wholesale Generators

- *Final Order February 10, 1992*
- *Requires*
  - *Sworn statement on Eligibility*
  - *Description of facility*
  - *Affiliations, if any*
  - *Any necessary state determinations*
- *No deficiencies / No amendments (60 day response)*
- *Case-By-Case determination (e.g. QFs can be EWGs)*
- *80 applications to date*
  - *64 Granted - 10 Denied - 2 Withdrawn - 4 Pending*

Transmission Information Rule (213(b))

- *Proposed: March 30, 1993*
  Final rule: September 30,1993

- *Requires analytical tools -- not analytical output*

  - *Regional loadflow base cases*
  - *Maps/System diagrams*
  - *Reliability criteria*
  - *Practices and procedures*
  - *Evaluation procedures*

  (All, except maps, in electronic format)

- *Adequate for screening analysis*
- *Data submittal on regional basis (where feasible)*
- *Minimal burden*
- *May aid development of RTGs*
- *Also 714 modifications -- hourly system lambda*

Policy Statement on Good Faith Requests and Responses (213a.)

- *Commission Issued Policy Statement on July 14, 1993*

- *Commission Endorsed Specific, Not Vague, Requests and Responses*

  - *Requests Must Be Specific Enough to be Modeled*

  - *Responses Must Be an Executable Contract If Capacity is Available, or a Study Agreement If Not*

- *Network Service May Be Requested*

- *Commission Requested Comments on Its Legal Authority to Order Network Service*

Overview of Transmission Access

- *Mandatory Access*
  - *New 211 Authority as a Result of the Energy Policy Act*
- *Voluntary Access*
  - *Market Based Pricing of Power Sales*
- *Mergers*

Mandatory Access Under Section 211 As a Result of Energy Policy Act of 1992

- *Commission Can order Transmission Service Upon Request if the Service:*
  - *Is in the Public Interest*
  - *Does not Unduly Degrade Reliability*
  - *Does not Involve Retail Wheeling (State and Local Issue)*
- *Who Can Request? Any Electric Utility, PMA or Independent Generator*
- *Who Must Provide Service? Any Electric Utility, including Those in ERCOT, Munis's, Coop's and PMAs*

Mandatory Access Under Section 211 (Cont.)

- *Administrative Procedure Can Be Lengthy:*
  - *Third Party Must Make a "Good Faith" Request to Utility*
  - *Transmitting Utility has 60 Days to Respond*
  - *Third Party Can Request Service Under 211*
  - *Commission Must First Propose an Order and Allow Parties to Consider It*
  - *Commission Then Can Order Transmission Service subject to Rehearing*
- *Four Cases Filed: One Denied - One Withdrawn - One In trial - One Pending*
- *Emerging Issues:*
  - *What Transmission Service is in the Public Interest?*
  - *Which Services? e.g., Network Service, Scheduling Service, Load Following*
  - *Can Transmission Service Be Ordered if There's an Existing Contract?*

Voluntary Access: Market Based Pricing Standards for Power Sales

- *Seller Lacks Market Power -- (Not Workable Competition, per se)*

- *Generation Market Power -- Seller Does Not Dominate the Relevant Market*

- *Transmission Market Power*

  - *Seller Cannot Block Competitive Suppliers from the Buyer*

  - *Open Access Transmission Tariff is Sufficient, but the Commission Has Not Required it*

  - *IPPs and Far-Away APPs Control No Transmission that Could Block Competitors*

  - *Seller Could Show that its Grid is Irrelevant to the Market, i.e., No Low-Cost Suppliers Can Be Blocked*

  - *De Minimis Argument in UI/Unitil Case*

Regional Transmission Groups

- *Policy Statement issued July 29th*
- *Policy Statement seeks:*
  - *Broad, contiguous membership*
  - *Commitment to provide Transmission service (including necessary expansion)*
  - *Develop and update Regional Transmission Plan*
  - *Fair Governance*
  - *Participation By State Regulatory Authorities*
  - *Alternative Dispute Resolution Procedures*
- *Progress in several regions*
  - *Western grid (Region and subregions)*
  - *Role of NERC*
- *Importance of RTGs*
  - *Consensus vs. contention*
  - *Quality and Timeliness of Decisions*
  - *State/Federal collaboration*

Overview of Transmission Pricing

Traditional Pricing -- Postage Stamp

Current Pricing Policy -- "And versus Or" Issue for Incremental Cost

Commission's Inquiry Into Possible Reform

- *And/Or Issue*
- *Firm Service: Parallel Path, Distance Sensitivity, and Contract Pricing*
- *Nonfirm Service: Capacity Charges and Spot Pricing*

ATTACHMENT B

in Wisconsin

1975 - Siting Law: an env. law

setup a 2 step process

All T-lines and generation additions must be approved in planning proceeding before they can be approved in a siting proceeding.

Plans redone every 3 years.

Wis. Institutional setting

2 - Reliability Councils

5 - IOUs

2 - Joint action agencies

1 - G + T Cooperative

T— Planning Process

(1) call from utility: Let's start

(2) Develop new set of T-system models for 5 + 10 + 15 years out.

(3) Run all possible single contingencies to ID problems

(4) Divide state up into sub regions that group problems

(5) Develop solutions to all problems

(6) Demonstrate that solutions work

(7) Write reports.

Transmission Access in Wisconsin

- PSCW ordered Wis Utils. to file wheeling Tariffs at FERC
  - all filed
  - court decided challenge to order was moot.
  - all tariffs approved by FERC

- PSCW ordered Wis. Utils. to develop CUSA s.
  - state court ruled against PSCW:- on procedural grounds - on preemption
  - Apealed directly to State Supreme Court: the couldn't decide
  - Request for review by Appelate Court denied. ??

Role of PSCW Staff in Utility Transmission Planning

— Making sure that the information that will be needed by the Commission in decision making is developed <u>during</u> the planning process.

— This includes information to address:

(a) standard criteria.

(b) questions that arise during planning process.

(1) Regulatory staff needs to participate in planning process

(2) Develop HCD standard criteria for analysis so problems are not missed

(3) Include environmental review early in planning process.

Provinces + States

Alberta
Arizona
British Columbia
California
Colorado
(Hawaii)
Montana
Nebraska
New Mexico
North Dakota
Oregon
Utah
Washington
Wyoming

Power Marketing Administrations

BPA
WAPA

Regional Energy Planning Organizations

NWPPC

National Governments + Agencies

USA
- FERC
- REA
- BLM
- NBS
- NFS

Canada
Mexico

most states have { Env/Siting agency, PUC }

26

3

7

Total Government Organizations ≥ 36

How can the diverse information needs of these gov. organizations be distilled down to a single level of RTG planning practice?

(1) Mutual agreement among states and other gov. organizations that RTG must develop information at a high enough level to meet the needs of all affected gov. organizations.

(2) Identify Highest Common Denominator information requirements so that RTG's being formed know what standard to implement.

ATTACHMENT E

S.Walton/20Oct93

AN OVERVIEW OF RTG ISSUES

Western RTG Discussions

- Sub-Regional
  - -- SWRTA -- Desert Southwest
  - -- WATSCO -- California
  - -- NWRTA -- Pacific Northwest
  - -- CCPG -- Colorado/Wyoming
- West-Wide
  - -- Investigate possible west wide RTG
  - -- Coordinate Sub-Regional efforts
  - -- Bylaws drafted for WRTA

Sub-Regional vs West Wide

- Sub-Regional
  - -- Need for local planning at lower voltages
  - -- Broader participation in meetings
  - -- Local contacts for members
  - -- "Easier" to put together?
- West-Wide
  - -- Consistent with scope of Western market
  - -- Elimination of "seams" problems
  - -- More opportunities for benefits
  - -- "Easier" to put together?
- Hybrid?

Contract vs Constitution

- Contract form
  - -- Attempts to deal with problems in advance
  - -- Leads to complex, detailed bylaws
  - -- Difficult to reach consensus
- Constitution
  - -- Shorter less complex bylaws
  - -- Creates an organization and allows it to grow over time
  - -- Complex arguments left to reach resolution when and if actual cases arise.

Main Bylaws Issues

- Association Governance
- Regulatory Participation
- Requests for Service
- Dispute Resolution
- Planning
- Pricing

Issues: Association Governance

- Membership Criteria
  - -- Anyone eligible for a§211 order
  - -- Withdraw at any time
- Classes of Members
  - -- Option #1: TOUs, TDUs, IPPs
  - -- Option #2: IOUs, POUs, IPPs, PMAs, etc.
  - -- Regulatory Class?
- Board Composition
  - -- Class balance
  - -- Geographic diversity
  - -- Voting procedures

Issues: Regulatory Participation

- Regulatory Class Members
  - -- State Rate Regulators (PSC, PUC, etc.)
  - -- Energy Comm., Dept., or Offices
  - -- Others?
- Areas of Participation
  - -- Board -- Selected representatives
  - -- Committees -- Interested participants

Issues: Requests for Service

- Use FERC Policy to define a "Good Faith" Request & Response
- Effect of requests on existing tariffs and contracts
- Ownership rights if a contribution in aid of construction is made?
- Available Transmission Capacity
- Planning horizon for prudent reserve?
- Reservations for non-firm needs?

Issues: Dispute Resolution Process

- A Mandatory Form
  - -- Mediation with Facilitator
  - -- Arbitration - modified "baseball" type
  - -- Appeal to FERC of arbitration award
  - -- PMA problems
- An Optional Form
  - -- Mediation
  - -- Opt for binding arbitration or
  - -- Opt to go directly to FERC

Issues: Nature of Dispute Resolution

- Scope of arbitration
- Selection of arbitrator(s)
- Structure of Award Appeals
  - -- For US Service Provider to FERC as a §211 request
  - -- For Canadian or Mexican Provider to ? ? ?
- Deference to RTG process

Issues: Planning

- Coordinated -- Not Centralized
- Relationship between RTG and WSCC
  - -- Bringing new participants into planning process
  - -- Meeting need for localized planning
  - -- Achieving a complimentary relationship
- WSCC Initiatives
  - -- Open membership
  - -- Data availability
  - -- Regional Planning Process -- Economic Issues

Issues: Pricing

- FERC Policy as the standard for US providers
- Standards for non-US providers
- No single methodology prescribed
- Advancing the "art"
  - -- Declaratory order
  - -- Appeal of arbitration award

Agenda

Regional Transmission Group Workshop

October 20-21, 1993

Monterey, California

Wednesday, October 20

8:30 a.m. ***Welcome, Purpose of the meeting and key issues for states***

* Jim Byrne (UT)
* Greg Basheda, DOE

9:00 a.m. ***Overview of the context of RTG discussions***

* FERC actions
  ** Steve Herod, FERC

9:45 a.m. ***Status of western RTG discussions***

** WATSCO
** SWRTA
** Northwest
** Colorado/Wyoming
** Westwide

10:15 a.m. Break

10:30 a.m. ***Alternative Approaches and Developments in Other Regions***

* Wisconsin
  * Mike Arny, Wisconsin PSC
* Interregional Transmission Coordination Forum (ITCF)
  * Bob Arnold, ITCF Chairman

11:30 a.m. ***Lunch***

12:45 p.m. ***Issue Discussions***

Overview of RTG issues

* Steve Walton, PacifiCorp

1:00 p.m. **Pricing**

* Review of pricing issues/options
  ** Steve Herod, FERC
* Relationship of pricing and RTGs
  ** Industry response panel[1]
* Illustration
  ** Western examples

2:30 p.m. Break

2:45 p.m. **Regional/Subregional RTGs**

* Key issues discussion
** Industry response panel
* Illustration
** Western examples with regional and localized impacts

3:45 p.m. **Transmission Planning**

* How transmission planning has historically been done
** Dennis Eyre, WSCC
* Key issues discussion (e.g., relationship between planning and access decisions; approaches to determining existing capacity/expansion needs; relationship with WSCC activities)
** Industry response panel
* Illustration
** Western examples

5:30 p.m. Adjourn

Thursday, October 21

8:30 a.m. ***Other issues***

* Role of power marketing administrations
** BPA/WAPA (invited)
** Industry response panel
* Role of Canadian/Mexican utilities
** Kashi Mattu, POWEREX
** Industry response panel
* Participation by states/provinces in RTGs
** Discussion

10:00 a.m. Recess

10:15 a.m. **State/Provincial discussions**

* State positions
* Response to FERC pricing inquiry
* Next steps on western RTGs
* Other

11:30 a.m. Adjourn workshop

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1. Invited to participate on the Industry Response Panels are: Steve Walton, PacifiCorp; Steve Larson, Bonneville Power Administration; Bill Claggett, Western Area Power Administration, Allan Vallow, Los Angeles Department of Water and Power; Roger Fontes, Northern California Power Agency; Bill Martin, Public Service Company of Colorado; Harlow Peterson, Salt River Project; Jim Kritikson, Southern California Edison; Chris Ellison, Independent Energy Producers; Bob Mooney, Consolidated Hydro; and Kashi Mattu, POWEREX.

FERC: Setting the Context of RTG Discussions

Following the enactment of the Energy Policy Act last November, the Federal Energy Regulatory Commission (FERC) has moved rapidly to establish the ground rules for exercising its authority to order transmission access, to issue a policy statement on its expectation regarding Regional Transmission Groups (RTG), and to begin a reevaluation of its transmission pricing policy. Five key actions have been taken by FERC:

- On September 30, the FERC issued a final rule on information utilities must file to allow FERC to determine if it should order transmission access (see Tab F for text of rule);

- On September 3, the FERC ruled that a submission by the Interregional Transmission Coordination Forum (ITCF) (a group of eastern U.S. utlities, IPPs and public power entities) did not constitute an RTG (see Tab G for text of decision);

- On July 30, the FERC issued its policy statement regarding RTGs (see Tab C for text of policy statement);

- On July 14, the FERC issued a policy statement establishing guidelines for "good faith" transmission requests and replies (see Tab E for text of policy statement); and

- On July 7, the FERC issued an inquiry on appropriate transmission pricing policies (comments due November 8)(see Tab D for text of notice of inquiry and FERC staff paper); and

Steve Herod, Director of FERC's Office of Electric Power Regulation, will review these, and other recent and pending FERC actions, which are forming the context within which RTG discussions are occurring. The states/provinces may want to explore the implications of these FERC actions with Steve. For example,

- When is FERC expected to decide whether it will set a new pricing regime for transmission services?

- What are the clues as to what FERC will consider acceptable in an RTG proposal (e.g., "Policy Statement Regarding Regional Transmission Groups," ITCF decision)?

- What does FERC view as the consequences of not establishing RTGs? What are the consequences for the Commission? What are the consequences for transmission-owning utilities? transmission dependent utilities? non-utility power suppliers?

- Does FERC expect a rash of transmission access requests or a trickle?

- What role does FERC envision for states in RTG operations? in review of appeals to the Commission from RTG dispute resolution processes?

Status of Western RTG Discussions

Western utilities and independent power producers have been working for some time to establish several subregional RTGs and/or one west-wide RTG. Bylaws have been drafted for: the Western Association of Transmission Systems Coordination (WATSCO), which thus far has involved California interests; the Southwest Regional Transmission Association (SWRTA), which has involved interests in Arizona, New Mexico, West Texas, southern Nevada and southern Utah; and the Western Regional Transmission Association (WRTA), which has involved interests throughout the western interconnected grid. Additionally, transmission principles have been agreed to by Wyoming and Colorado utilities (as part of the FERC's approval of the acquisition of the assets of the bankrupt Colorado Ute Electric Association), and Northwest interests have been holding regular discussions for some time.

At the workshop, representatives of each of the RTG groups will provide brief reports on the status of those discussions, as well as participate in the discussion of RTG issues. (See the following tan page for a report on the status of WATSCO discussions.)

The following white pages are a staff summary comparison of the provisions being considered by each of the RTG groups. The summary organizes the issues into categories identified by the FERC in its policy statement on RTGs. The level of detail among the RTG groups varies widely and some of the information may be dated. The most detailed information was available from the March 31, 1993 WATSCO Bylaws (see Tab I and the September 21, 1993 WART Bylaws and errata sheet (see Tab H). The information on SWRTA was derived from a speech by Harlow Peterson, Salt River Project. The information on Colorado/Wyoming activities is from an agreement between Public Service Company of Colorado and Tri-State Generation & Transmission. The information on Pacific Northwest discussions is from an October 1992 presentation by BPA to the Committee on Regional Electric Power Cooperation.

CALIFORNIA MUNICIPAL UTILITIES ASSOCIATION

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JERRY JORDAN, Executive Director

September 30, 1993

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Executive Director
Western Interstate Energy Board
600 17th Street, Suite 1704 South Tower
Denver, Colorado 80202-5447

Re: WATSCO BYLAWS

Dear Mr. Larson:

Roger Fontes of NCPA asked that I respond to a request from Jim Byrne to provide you with an "...up-to-date copy of the WATSCO bylaws and a short report on the status..." of WATSCO discussions. I am enclosing a copy of the March 31, 1993 draft of the WATSCO Bylaws. This is the last negotiated version of the bylaws and was approved "in concept" by all municipal utilities that had been involved in the negotiations as well as representatives of Independent Energy Producers and the Geothermal Resources Association. To our surprise and disappointment, none of the investor-owned utilities were willing to sign a Memorandum of Understanding expressing the parties' conceptual approval. Since that time there have been no further negotiating sessions involving all of the parties to the WATSCO negotiations.

However, commencing in August, LADWP and SCE have held discussions in an attempt to resolve a list of outstanding issues. These talks are confined to these two parties in hopes that issues may be resolved more expeditiously when only two parties are involved. If LADWP and SCE are successful, they will circulate a set of proposed amendments to the March 31 draft among the remaining parties to the WATSCO negotiations. If these amendments are acceptable or nearly acceptable to a "critical mass" of the parties, then I would expect rapid and successful conclusion to WATSCO negotiations. If, on the other hand, LADWP and SCE are unable to reach agreement fairly soon, or if they reach an agreement that is not acceptable to most other parties, then we can probably lay WATSCO to rest.

As I am sure you are aware, discussions have begun on draft bylaws for a "Westwide" RTG. Many parties, including CMUA, are involved in these discussions, and at this point they hold out some promise of a workable outcome.

I hope this information is helpful in preparation for your RTG workshop. We wish you success. Please let us know if we can be of any other assistance.

Sincerely,

Stuart E. Wilson
Assistant Executive Director

enclosure

cc: Roger Fontes

BASIC COMPONENTS OF FERC'S RTG POLICY STATEMENT COMPARED WITH PROVISIONS OF DRAFT RTG BYLAWS

1. **FERC:** *An RTG agreement should provide for broad membership (including foreign utilities) and encompass an area of sufficient size and contiguity to promote economic efficiency.*[1]

Western Regional Transmission Association (WRTA)[2]: Three basic types of organizations are eligible for WRTA membership: (1) Transmission Providers - entities owning or having contractual rights to use transmission facilities; (2) Transmission Users - entities qualified to apply to FERC for an order requiring a transmitting utility to provide transmission services pursuant to §211 of the Federal Power Act (FPA); and (3) Commissions - state utility regulatory agencies and energy commissions which are non voting, ex officio members. Each member organization must operate or be located within the jurisdiction of the Western Interconnection, which is comprised of the states and provinces of Western Canada, Northern Mexico and the Western United States. (WRTA, §§2, 3)

Western Association For Transmission Systems Coordination (WATSCO)[3]: Organizations eligible for WATSCO membership include: "any entity generating electric energy for sale for resale as defined in Section 211 of the FPA and all publicly owned and investor owned electric utilities, rural electric cooperatives, Federal power marketing agencies, state agencies owning or planning transmission or generation, joint power agencies of electric utilities, non-utility generators, and other transmission owners." (WATSCO, §1.7) Regulatory and governmental agencies with jurisdiction are eligible to be ex officio, non voting members only. The Bylaws do not specifically define the geographic area within which members must operate or be located. (WATSCO, §8.1)

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[1]The seven basic components of an RTG agreement identified in this document were originally presented in FERC's Policy Statement Regarding Regional Transmission Groups issued on July 30, 1993. (Docket No. RM93-3-0001)

[2]Information on WRTA was culled from their September 21, 1993 draft Bylaws.

[3]Information on WATSCO was culled from their March 31, 1993 draft Bylaws.

Southwest Regional Transmission Association (SWRTA)[4]: Membership is open to all segments of the utility industry, including transmission owners, transmission-dependant utilities, independent power producers, wholesale power consumers, and regulatory bodies. Currently, SWRTA encompasses the following contiguous areas: Arizona, New Mexico, West Texas, Southern Nevada, Southern Utah, Southern California, and Colorado. (Energy Conference, pp. 18, 19; Regional Electric Power Cooperation, Attachment L)

Colorado/Wyoming[5]: Colorado Public Service and Tri-State are the only signatories to the bilateral policy statement. The policy statement does not contain provisions for adding additional members, nor does it define the geographic reach of the transmission system.

Northwest[6]: The following organizations have participated in on-going discussion group activities: all Northwest investor-owned utilities, the Public Power Council, Seattle City Light, Grant County PUD, BPA, Northwest Cogeneration Coalition and Idaho Independent Energy Council. It is expected that membership will be open to all Northwest utilities, generators and power marketing administrations. Membership may be open to Canadian participants as well. The geographic area of a Northwest RTG is not clearly defined. (Regional Electric Power Cooperation, Attachment L)

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[4]SWRTA's analysis is not based on a review of its draft Bylaws. Pertinent information was gathered from remarks by Mr. Harlow Peterson on "A Case Study in Regional Transmission Group Development" presented to The Energy Daily Conference on September 21, 1993 and from the "Summary of the October 8-9, 1992 Meeting of the WIEB Committee on Regional Electric Power Cooperation."

[5]This entry does not constitute an RTG per say, rather it represents a cooperative agreement between two transmission owning organizations, Public Service Company of Colorado (Colorado Public Service) and Tri-State Generation and Transmission Association (Tri-State). The bilateral agreement entered into by these organizations on December 16, 1991 is called the Electric Transmission Service Policy Statement. This agreement outlines the terms and conditions by which wholesale transmission service will be provided from these organizations' jointly-owned and separately-owned transmission facilities to third parties.

[6] Relevant information was culled from the "Summary of the October 8-9, 1992 Meeting of the Committee on Regional Electric Power Cooperation." According to that document, bylaws have not yet been developed for a Northwest RTG. Instead, Northwest RTG discussion participants have focussed on formulating a set of defining principles. (Regional Electric Power Cooperation, Attachment L)

2. FERC: *An RTG agreement should provide for a means of adequate consultation and coordination with relevant state regulatory authorities. State participation is encouraged.*

Western Regional Transmission Association: WRTA allows its membership to include state utility regulatory bodies and energy commissions. Although member Commissions are not afforded voting privileges, they will have access to transmission planning information collected from the other member organizations by the Planning Committee. Additionally, member Commissions will be allowed to participate in both WRTA general and committee meetings. (WRTA, §5.2)

Western Association For Transmission Systems Coordination: WATSCO permits regulatory and governmental agencies with jurisdiction to be ex officio, non voting members. The Board shall designate no more than two representatives from "such regulatory and/or governmental agency" with jurisdiction to be members of the Board and the Planning Committee. (WATSCO, §8.12) Notwithstanding their non voting status, ex officio members will have access to the Planning Committee's information repository and will be allowed to participate (in a non voting capacity) in Board meetings, committee meetings and annual meetings of the full membership. (WATSCO, §8.6)

Southwest Regional Transmission Association: SWRTA recognizes the importance of federal and state regulatory agency participation. It has consulted with FERC and other state regulatory bodies to help with the drafting of its Bylaws. (Energy Conference, pp. 20, 22)

Colorado/Wyoming: The policy statement does not provide for state participation.

Northwest: Not enough information is available to permit commenting on this section.

3. *FERC: An RTG agreement should impose on member transmitting utilities an obligation to provide transmission services for other members. RTG members should be assured that they can obtain transmission services similar to those that FERC could order under §211 and §212 of FPA. The terms and conditions under which transmission services will be offered should be specified.*

Western Regional Transmission Association: Each member Transmission Provider is obligated to provide transmission services to any member Transmission User on a basis consistent with the following: (1) the FPA; (2) FERC's standards and policies; (3) a Transmission Provider's FERC approved tariffs; (4) negotiated service agreements among members; and (5) arbitration awards. Transmission Provider members that are not subject to the provisions of §211 of the FPA will be obligated to provide transmission services in a manner consistent with the FPA. Additionally, it should be noted that members will not be obligated to provide transmission services of a type which are not in accordance with §211 of FPA. Any Transmission User requesting transmission service shall submit its request, along with relevant backup documentation, to a Transmission Provider in a manner consistent with FERC's current policies governing such requests. Upon receipt of a transmission service request, the Transmission Provider is obligated to respond pursuant to §212 of FPA and FERC's policies and standards. Transmission Providers reserve the right to either provide the requested services, if Available Transmission Capacity[7] exists, or initiate studies to determine the feasibility of satisfying the request. Feasibility studies are conducted at the Transmission User's expense and are to be made available to all members. If the studies demonstrate both a need for and feasibility of enlarging existing facilities, or for providing an interconnection, the Transmission User may elect to have the Transmission Provider build the expansion facilities. The Transmission provider is obligated to construct the project in accordance with the findings of the feasibility study and the terms negotiated with the Transmission User. All planning and construction activities related to the expansion of existing transmission capacity are subject to applicable state and local laws in addition to FPA and FERC standards and policies. (WRTA, §10)

Western Association For Transmission Systems Coordination: Any Transmission Provider receiving a request for transmission service shall notify the Planning Committee of the request. In addition, the Transmission Provider shall notify the Transmission Requester of the following determinations: (1) whether sufficient transmission capacity exists to satisfy the

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[7] Available Transmission Capacity is capacity "not reasonably required to accommodate the Transmission User's (i) Native Load; (ii) existing commitments for wholesale sales contracts; (iii) existing contractual and statutory commitments for firm transmission service; and (iv) Prudent Reserve." (WRTA, §2.3) Native Load is defined as the "[l]oad associated with retail customers and full or partial requirements wholesale customers for which a Transmission Provider, by statute, franchise, contract or FERC policy or regulation, has undertaken the obligation to plan, construct and operate its system to provide reliable service." (WRTA, §2.14) Prudent Reserve refers to the "amount of transmission capacity set aside for a Transmission Provider's reasonable reliability requirements as determined by the reliability criteria of such Member and consistent with Prudent Utility Practice and regional reliability council criteria, which requirements shall be impartially applied without undue discrimination." (WRTA, §2.17)

request without further study; (2) whether a study is necessary to assess the feasibility of satisfying the request with available transmission capacity[8], or through incremental additions[9]; and (3) whether the requested service is available in light of other member's/members' request(s) for transmission service. Transmission Providers are obligated to provide transmission services to any requesting member when transmission capacity is available. Under circumstances when a Transmission Provider lacks available capacity to satisfy a member's request, the Transmission Provider must make a good faith effort to increase transmission capacity through incremental additions. However, if a Transmission Provider is unable to obtain all necessary rights, permits and approvals associated with the incremental addition, then the Transmission Provider shall be freed of its obligation to enlarge to its transmission facilities. Tax exempt utilities whose tax status would be threatened by providing transmission access (1) can deny access or (2) provide access and accept compensation for the loss of tax exempt status. Overall, WATSCO's Bylaws provide much detail with respect to the transmission service points highlighted in this section. For example, WATSCO states that the Transmission Requester may provide capital to cover the incremental transmission construction costs where a regulatory authority has denied the inclusion of the incremental transmission costs in the Transmission Provider's rate base. (WATSCO, §§5.1, 5.2, 5.3, 5.3.2, 5.3.3, 5.3.5, 5.8, Appendix A)

Southwest Regional Transmission Association: SWRTA acknowledges the significance of this basic component of an RTG agreement. However, the specific provisions in SWRTA's draft Bylaws relating to transmission service are not known as of the time of this writing.

Colorado/Wyoming: According to the policy statement, both Colorado Public Service and Tri-State will provide wholesale transmission service to any requesting utility or non-utility electric power supplier when transmission capacity is available. Upon receipt of a written request for transmission service, Colorado Public Service and/or Tri-State will assess the existing transmission capacity of the system to determine if sufficient capacity is available. If that assessment demonstrates a need to enlarge existing transmission facilities, the requester will be notified that additional studies will be required to determine the feasibility of such transmission additions. In the event that a requester wishes either of the transmission providers to proceed with the construction of the transmission additions, the requester shall be

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[8] WATSCO defines Available Transmission Capacity as capacity not needed for existing and planned native load, existing firm transmission service contracts, existing and planned native load of customers within a member's control areas, transmission capacity temporarily committed to competitive resource acquisition and prudent reserve. (WATSCO, §3.1) Prudent Reserve refers to the "amount of transmission capacity set aside for one or more of the following: (i) A utility's reasonable reliability requirements consistent with Prudent Utility Practice; and (ii) Inadvertent flows and loop flow." (WATSCO, §3.17)

[9] Incremental additions are defined as "[a]dditions, improvements or capital betterments (including interconnection facilities) to a Member's/Members' electric transmission system reasonably required for the purpose of increasing transmission capacity to accommodate a transmission service request of another member." (WATSCO, §3.9) Future increase or decreases in the rating of the capacity of an incremental addition shall be ascribed to the Transmission Provider. (WATSCO, §5.3.4)

obligated to "pay for the appropriate costs, including the ongoing ownership costs, associated with such design and construction of the facilities and associated services provided." (Policy Statement, p.5) Additionally, Colorado Public Service and Tri-State will attempt to form an interconnection with any requesting utility which is not interconnected with the transmission system. Lastly, the policy statement requires that any utility or power supplier receiving transmission service from either transmission provider must "meet the applicable Reliability Criteria for System Design, the Minimum Operating Reliability Criteria and adhere to the Operating Procedures set forth by the Western Systems Coordinating Council for deliveries in that Council area...." (Policy Statement, p. 3)

Northwest: The Northwest discussion group supports FERC's requirement that member transmitting utilities should be obligated to provide transmission services to other members. The Northwest group also believes that its RTG should have authority over both firm and nonfirm transmission services. (Regional Electric Power Cooperation, Attachment L)

4. FERC: *An RTG agreement should require the development of a coordinated transmission plan on regional basis and the sharing of transmission planning information. Regional plans should involve the needs of non members in the surrounding areas having transmission assets that interact with those of the RTG. An RTG agreement should also include details concerning its operational and planning procedures.*

Western Regional Transmission Association: The Board appointed Planning Committee's primary objective is to coordinate WRTA transmission planning activities. To facilitate the coordinated planning process, the Planning Committee will establish procedures which promote the exchange and sharing of transmission information among the membership. These procedures will require members to submit certain transmission information to the Planning Committee which shall include, but is not limited, to the following: (1) internal planning criteria[10]; (2) system data; (3) proposed project transmission studies: and (4) an annual report from each member Transmission Provider providing information on each member's existing and planned Interconnected Transmission System. The Planning Committee will also help coordinate member Transmission Provider's submission of reports regarding the availability of transmission capacity to FERC pursuant to §213(b) of the FPA. Members may participate in any proposed transmission projects within WRTA jurisdiction. In its capacity as a transmission information clearing house and centralized coordinating body, the Planning Committee will help WRTA interface with Western Systems Coordinating Council, Subregional Coordination Groups, government regulatory authorities, member organizations, and non member organizations. (WRTA §9)

Western Association For Transmission Systems Coordination: A Planning Committee will be established for the purpose of coordinating transmission access, operation and development on a regional and subregional basis in order to accommodate bulk transmission needs. So that each member will understand the capacities and constraints of the transmission system, the Planning Committee will make certain transmission information available to the membership by creating a planning information repository. The Planning Committee will require each member to submit a number of substantive transmission planning documents. The information contained in these documents shall include: (1) planning criteria[11]; (2) intertie

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[10]Individual Transmitting Utilities' reliability criteria shall be consistent with Prudent Utility Practice. According to the Bylaws, Prudent Utility Practice encompasses "[t]hose practices, methods and acts, including levels of reserves and provisions for contingencies, as may be modified from time to time, that are commonly used in the Western Interconnection to: (i) operate electric systems dependably, reliably, safely, efficiently, economically and in accordance with all applicable laws and governmental rules, regulations and orders; (ii) serve customers; and (iii) prevent material adverse effects on neighboring electric systems." (WRTA, §2.18)

[11]According to the Bylaws, reliability criteria shall be consistent with Prudent Utility Practice. WATSCO defines Prudent Utility Practice as "[t]hose standards (including current published reliability criteria, standards and guidelines of the Western Systems Coordinating Council and the North American Electric Reliability Council), practices, methods and equipment that are currently and commonly used by the electric utilities to plan, engineer, select, operate, schedule and maintain electric power facilities and equipment reliably and

transmission data; (3) Long Term Transmission Plans, which will include among other information (a) available transmission capacity, (b) current and expected transmission use, (c) location of transmission constraints, and (d) existing commitments for transmission service; (4) resource plans associated with the Long Term Transmission Plans; and (5) existing generation and transmission system data and systems representations; (WATSCO, §4.7) Each member is "encouraged" to provide its generation development plans and requirements for transmission necessary to implement the generation plans. Each of the member's draft long-term transmission plan are distributed to other members for review and comment. Thereafter, each member prepares a final plan. Every two years the Planning Committee will compile the information contained in each member's Long Term Transmission Plan and resource plan into a single comprehensive report. The Bylaws also require each member planning incremental additions and\or improvements to its transmission facilities to notify the Planning Committee. The Planning Committee will then notify the full membership of such proposed activity. Coordinated planning will also strive to "mitigate... the detrimental effects of parallel path flows on each Member's system and utility systems interconnected thereto." (WATSCO, §4.4) Based on the transmission information submitted to it, the Planning Committee may also make recommendations to the Board concerning "inter- and intra-control area transmission transfer capability...." (WATSCO, §9.4) WATSCO Bylaws include detailed provisions with respect to transmission planning activities; the Bylaws do not indicate the extent to which the Planning Committee will involve the needs of non members. (WATSCO, §§4, 9, Appendix A)

Southwest Regional Transmission Association: SWRTA recognizes that it is necessary to incorporate the needs of both transmission owners and users when planning for the use and development of the interconnected system at the subregional level. (Energy Conference, p. 24) Exactly how SWRTA will accomplish this goal is not known as of the time of this writing.

Colorado/Wyoming: Colorado Public Service and Tri-State agree to pursue a "single-system" coordinated planning strategy. A "single-system" planning strategy is one that involves transmission providers and other affected utilities formulating planning decisions as if the bulk transmission system were owned by a single entity. Colorado Public Service, Tri-State and other participants will therefore strive to utilize existing transmission capacity in an efficient manner and plan for the development of the system in a cooperative atmosphere. Furthermore, the transmission providers acknowledge that all affected participants in the system are "entitled to an opportunity to invest or otherwise responsibly share in the benefits and the costs of system enhancements associated with new generation and transmission additions." (Policy Statement, p.2) The policy statement does not contain provisions regarding the sharing of transmission planning information, nor does it elaborate on operational and planning procedures. (Policy Statement, pp. 1,2)

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efficiently to serve their customers dependably and economically with due regard for the conservation of natural resources, protection of the environment and the state of the art in the electric power industry as applied in the WSCC area." (WATSCO, §3.18)

Northwest: The Northwest discussion group endorses this component of an RTG agreement. However, not enough information is available to permit further comment on this section. (Regional Electric Power Cooperation, Attachment L)

5. **FERC:** *An RTG agreement should include fair and non-discriminatory governance/voting procedures. The rights of all members in an RTG should be protected by institutionalized mechanisms.*

Western Regional Transmission Association: Each member organization, other than a Commission, is entitled to a single vote on any matter. To prevent any one organization or group of organizations from wielding a disproportionate amount of voting power, the membership is divided into four classifications: (1) Major Transmitting Utility; (2) Transmission-Dependant Utility; (3) Nonutility Supplier; and (4) Commission (non voting). For any measure to be adopted or settled (elections excluded) two-thirds of the members of each voting classification in attendance must vote affirmatively. A quorum consists of a simple majority of the total membership with voting rights. WRTA membership will create a 21 member Board of Directors comprised of seven members from each of the three voting member classifications. In addition, the Board shall be selected in a manner which assures the fair balance of the membership's geographic diversity. Quorum requirements and voting procedures for the Board are the same as those for the general membership. Additionally, the Board has the authority to appoint and disband special committees whose membership is allocated to reflect the geographic diversity of the general membership and the fair representation of member classifications. (WRTA §4, §5) Lastly, in the event that FERC issues an order requiring substantive changes to the Bylaws, the Bylaws shall cease to have any binding effect on the membership.

Western Association For Transmission Systems Coordination: Each member organization, other than a regulatory or governmental agency, is entitled to one vote on any matter. The general membership will be governed by a twelve member Board of Directors. Three Board members representing one of each of the following four categories will be elected by a majority vote of the members of that corresponding group: Category 1- investor-owned utilities; Category 2- publicly owned utilities and joint power agencies; Category 3- non-utility generators; and Category 4- federal power marketing administrations, rural electric cooperatives, and state agencies owning transmission. The Board of Directors shall designate no more than two representatives from regulatory and/or governmental agencies from each state with jurisdiction to be ex officio (non voting) members of the Board. The Board will preside over all WATSCO matters including adopting a list of qualified arbitrators and supervising committees, but will not elect its own members, nor approve proposed changes to the Bylaws. The President of the Board may appoint special committees, hire staff and enter into contracts. Changes to the Bylaws will require an affirmative vote by two-thirds of the members of each category in attendance. It should also be noted that the Bylaws will be interpreted and governed by the laws of the State of California. (WATSCO, §§8.6- 8.17, 12.1)

Southwest Regional Transmission Association: SWRTA acknowledges that any RTG agreement should include provisions satisfying this minimum requirement. (Energy Conference, p. 15) However, how SWRTA intends to fulfill this requirement is not known as of the time of this writing.

Colorado/Wyoming: Not applicable.

Northwest: The discussion group expects that a Northwest RTG will be governed by a Board of Directors. Further details regarding governance and voting procedures are not available. (Regional Electric Power Cooperation, Attachment L)

6. FERC: *An RTG agreement should include high quality alternative dispute resolution (ADR) procedures for resolving transmission issues. ADR proposals which afford FERC deference to outcomes resulting from voluntary ADR procedures are especially encouraged.*

Western Regional Transmission Association: WRTA members have access to two successive means of resolving disputes related to transmission access or service issues. The first procedure requires the disputing members to attempt to negotiate a resolution with the assistance of an impartial facilitator selected from the membership. If this effort fails, the disputing members shall commence a binding arbitration process. WRTA Bylaws detail a method of selecting an arbitrator in the event that disputing members can't agree upon one. The arbitrator will decide on the particular arbitration procedures to be adhered to in the matter and shall select the proposed award (decision) which best satisfies the intent of the Bylaws and conforms with the FPA and FERC's standards and policies. The selected award is considered binding unless a disputing member decides to pursue an appeal before FERC. A member may appeal an award to FERC only upon the grounds that the award is contrary to the intent of the Bylaws, or "unjust, unreasonable, unduly discriminatory or preferential or otherwise inconsistent with the FPA or FERC's standards and policies." In the event of an appeal to the FERC, such appeal shall be based on the record assembled by the arbitrator, but no deference shall be afforded to the conclusions or judgements reached by an arbitrator. Lastly, an arbitrator is prohibited from selecting an award which could not be ruled on by FERC under §212(h) of FPA. (WRTA §12)

Western Association For Transmission Systems Coordination: In the event that disputing members are unable to negotiate a resolution to a matter relating to the Bylaws, any member party to that dispute may initiate a binding arbitration process. All matters relating to Bylaw provisions are subject to arbitration with the following exceptions: (1) a Transmission Provider's selection of facilities to be used in satisfying a request; (2) published reliability criteria consistent with Prudent Utility Practice; (3) reliability criteria of a member utility published as of January 1, 1992 and consistent with Prudent Utility Practice; (4) executed contracts; (5) the legitimacy of any request for transmission service; (6) ownership issues relating to facilities providing transmission services beyond the scope of the Bylaws; (7) "...forecasts of service area demand adopted following a public hearing by a state's energy planning agency and any assumptions subject to a regulatory agency order..." that help determine planned native load. (WATSCO, §10.1.2); and (8) compensatory damages. The process by which a party initiates arbitration is specified in the Bylaws. After a disputing member has served written notice of pending arbitration to all concerned parties, a panel of three arbitrators shall be selected in accordance with the Bylaws. At this time, any WATSCO member or non member (including a state or federal agency) wishing to intervene may do so pursuant to the terms and conditions of the Bylaws. The panel of arbitrators will have the authority to determine the method, schedule and scope of the arbitration process and shall select the award which "...best meets the standards and intent of these Bylaws and is consistent with Prudent Utility Practice and applicable state or federal law (including the Federal Power Act)." (WATSCO, §10.5.2) The selection of the award is binding on all

parties to the arbitration, including member and non member intervenors. All parties and intervenors in a dispute resolution proceeding "shall submit and fully support" the arbitration decision before any regulatory authority. (WATSCO, §10.9) However, in the event that an award is denied "legally required approval of a Regulatory Authority," then that arbitration decision shall not be binding upon the affected members. (WATSCO, §10.9) Any party to an arbitrated dispute may appeal an award to FERC "only upon the grounds that the award is contrary to, or beyond the scope of, these Bylaws or is inconsistent with any then applicable FERC certification order with respect to these Bylaws, or is unjust, unreasonable, unduly discriminatory or preferential." (WATSCO, §10.6) WATSCO Bylaws include extensive provisions governing dispute resolution proceedings. (WATSCO, §10)

Southwest Regional Transmission Association: SWRTA endorses this basic component to an RTG agreement, but as of this writing it is not known which ADR procedures it plans to adopt. (Energy Conference, p. 15)

Colorado/Wyoming: In the event that Colorado Public Service and/or Tri-State are unable to resolve a dispute with a requester through good faith negotiations, either party may submit the dispute to arbitration. Matters that are subject to arbitration include any issues associated with the performance of the provisions of the policy statement and disputes concerning the construction of new transmission facilities pursuant to a request for transmission service. The arbitration process begins when one party to a dispute serves written notice to the other. Following receipt of that notice, the disputing parties shall each select an arbitrator who has knowledge of the issues involved. The two arbitrators will then select a third arbitrator. If the first two arbitrators are unable to agree on the selection of a third arbitrator, a court shall designate one. The applicable rules and practices that shall govern the arbitration process are specified in the policy statement. Lastly, the arbitrators decision is limited to the proposed awards submitted by the parties and shall be binding unless the parties have agreed to non-binding arbitration. (Policy Statement, p.6, Attachment A)

Northwest: Discussion group participants support binding arbitration as an appropriate ADR procedure. Discussion participants further note that while parties to an arbitrated dispute do not have to actively support decisions before a regulatory body, they must not oppose them either. (Regional Electric Power Cooperation, Attachment L)

7. **FERC:** *An RTG agreement should include detailed exit provisions for members that leave the RTG.*

Western Regional Transmission Association: Any member may withdraw from WRTA by providing written notice to the Board and FERC. All arbitration decisions and transmission services to be provided by a withdrawing organization must be honored if such prior obligations are in effect or pending as of the date of receipt of the withdrawal notice. However, pending requests for transmission services to be provided to the withdrawing organization shall be considered void. In the event that a member voluntarily withdrawals, that organization may not reapply for a period not less than one year. However, if the Board decides to revoke an organization's membership that organization may not reapply for a period of time specified by the Board which shall not exceed five years. (WRTA §3.4, §3.5)

Western Association For Transmission Systems Coordination: Any member may withdraw from WATSCO by providing advance written notice to the Board. Requests for transmission service, noticed prior to the effective date of withdrawal, must be honored by the withdrawing member. However, if a transmission service requester withdraws from the membership prior to the completion of the processing of a request, that service request shall be determined null and void. Lastly, all contracts and decisions stemming from dispute resolution proceedings will be binding upon withdrawing members. (WATSCO, §§8.3.1, 8.3.2)

Southwest Regional Transmission Association: SWRTA intends to include this provision in its Bylaws. (Energy Conference, p. 15)

Colorado/Wyoming: Not applicable.

Northwest: Not enough information is available to permit commenting on this section.

8. Other Key Provisions

Subregional Coordination Groups

Western Regional Transmission Association: Members are allowed to form Subregional Coordination Groups on the condition that their bylaws do not contradict the terms and intent of WRTA bylaws. The Board evaluates the proposed bylaws of a Subregional Group and has the power to authorize or disapprove of a Group's formation. The chairpersons of all Subregional Groups also sit on the Planning Committee. (WRTA, §6.6, §6.10)

Western Association For Transmission Systems Coordination: The Bylaws do not include explicit provisions regarding subregional coordination and group formation. However, the California based WATSCO can be viewed as a subregional RTG existing within the framework of the west-wide WRTA RTG.

Southwestern Regional Transmission Association: SWRTA believes that most transmission planning initiatives will be implemented at the local subregional level versus the broader regional level. However, it also feels that it can perform effectively as a subregional RTG within a regional RTG encompassing the entire Western United States. (Energy Conference, p. 27)

Colorado/Wyoming: Not applicable.

Northwest: Once the discussion participants approve the set of defining principles, membership in a west-wide RTG will be considered. (Regional Electric Power Cooperation, Attachment L)

Pricing

Western Regional Transmission Association: The pricing of transmission services provided by a Transmission Provider shall adhere to the pricing procedures, methodologies and tariffs approved by FERC and in accordance with FPA. In addition, each member reserves the right to unilaterally appeal to FERC for a change in rates or rate methodologies. (WRTA, §14) Furthermore, any Transmission Provider wishing to use a different pricing mechanism not already approved by FERC must appeal to FERC for authorization. Member Transmission Providers in Canada and Mexico may rely upon the pricing policies of regulatory agencies other than FERC only if such policies are "no less favorable to Transmission Users than those established by FERC." (WRTA, §10.1)

Western Association For Transmission Systems Coordination: According to the Bylaws, the pricing of transmission services "shall be cost-based and shall not be at the expense of the customers or owners of the Member providing such services." (WATSCO, § 5.4) The Bylaws further note that cost-based pricing shall be determined in a manner consistent with FERC regulations and FPA. Rates for transmission service (including rate methodology and

design) are to be negotiated by the Transmission Provider and any client Transmission Requester. Pending agreement on the rate and the terms and conditions of the transmission service, the parties to the agreement shall execute a service contract and file the necessary information with FERC. In the event that a Transmission Provider and requester are unable to negotiate a service contract, the parties shall submit the dispute to binding arbitration. (WATSCO §§5.4.1, 5.4.2, 5.4.3)

Southwestern Regional Transmission Association: Not enough information was found to permit commenting on this section.

Colorado/Wyoming: Rates for transmission service are those on file with FERC. A pro rata share of any new facilities will be paid by the transmission requestor. (Policy Statement, p. 6-7)

Northwest: Cost-based rates, including opportunity costs and incremental costs shall be adopted. (Regional Electric Power Cooperation, Attachment L)

Canadian and Mexican Membership

Western Regional Transmission Association: As previously mentioned, WRTA membership is open to western Canadian and northern Mexican organizations. The Bylaws provide that "Canadian or Mexican Transmission Providers may establish prices based upon policies different than, but no less favorable to transmission users, than those established by the FERC" (WRTA, 10.1)

Western Association For Transmission Systems Coordination: The Bylaws do not specifically address the issue of foreign membership and/or system interconnection.

Southwestern Regional Transmission Association: Unknown.

Colorado/Wyoming: Not Applicable.

Northwest: Membership may be open to Canadian organizations. The fact that Canadian utilities are not subject to FERC transmission orders remains to be an unresolved issue. (Regional Electric Power Cooperation, Attachment L)

Relationship to WSCC

Western Regional Transmission Association: The Planning Committee will interface with WSCC for purposes of coordinating and preparing member information and transmission planning information to be submitted to WSCC, FERC and other regulatory bodies. (WRTA, §9.1, 9.2, 9.4)

Western Association For Transmission Systems Coordination: The Planning Committee will "encourage all Members to seek membership in WSCC in order to maximize consistency of data, minimize disputes over access to data and models, and reduce the need for duplicative study efforts...." (WATSCO, §9)

Southwestern Regional Transmission Association: WSCC criteria, guidelines and policies are expected to be adhered to. Eventually, SWRTA could be merged with the WSCC. (Energy Conference, p. 23)

Colorado/Wyoming: As previously mentioned, any utility or wholesale power supplier receiving transmission service from Public Service and/or Tri-State must adhere to the Operating Procedures of the WSCC. (Policy Statement, p. 3)

Northwest: WSCC criteria, guidelines and policies are expected to be adhered to. (Regional Electric Power Cooperation, Attachment L)

Retail Wheeling

Western Regional Transmission Association: With respect to dispute resolution proceedings, no member shall be obligated to provide transmission services which could not be ruled on by FERC pursuant to §212(h) of the FPA. (WRTA, §13)

Western Association For Transmission Systems Coordination: Members will not be expressly prohibited or required to participate in any retail wheeling arrangements. (WATSCO, §5.9)

Southwestern Regional Transmission Association: Members will not be required to "wheel directly to end-use consumers." (Regional Electric Power Cooperation, Attachment L)

Northwest: Members will not be obligated to engage in wheeling activities with end-use consumers. (Regional Electric Power Cooperation, Attachment L)

RTG Participation Costs

Western Regional Transmission Association: 25% of all administrative costs will be allocated on a per capita basis among the membership, excluding Commission members. The remaining 75% will be allocated among the full membership based upon total revenues from electricity sales. (WRTA, §8.1) The costs associated with planning studies and other planning activities will be allocated among those members benefitting from the planning activities on a basis proportionate "to the amounts of transmission capacity in megawatts desired by each participating Member." (WRTA, §8.2)

Western Association For Transmission Systems Coordination: Bylaws do not contain a membership dues structure. However, with respect to transmission study costs, Transmission Providers reserve the right to require Transmission Requesters to pay for all or part of the costs associated with the performance of the transmission study. (WATSCO Appendix A, §II)

Southwestern Regional Transmission Association: Unknown.

Colorado/Wyoming: Not applicable.

Northwest: Unknown.

Alternative Approaches and Developments in Other Regions

In at least three regions outside the West there have been significant developments affecting transmission planning and access: Wisconsin; the ITCF region; and New England. In Wisconsin, the state has adopted a planning model that includes a long-term planning and siting pre-approval process. Before facilities can be approved in a construction proceeding, they must have received approval in a planning proceeding. Wisconsin believes its approach is a model of a regional planning process that provides decision makers a foundation for making complex decisions about transmission additions. Michael Arny from the Wisconsin Public Service will discuss the Wisconsin approach, including the status of legal issues surrounding its implementation. (See tan pages for an article on Wisconsin's approach.)

The Interregional Transmission Coordination Forum (ITCF), a voluntary association of utilities, independent power producers and public power entities in the eastern U.S. formed coordinate and resolve disputes over transmission issues, submitted a filing to the FERC. In its September 3, 1993 decision, the FERC found that "[t]his coordination group does not constitute a regional transmission group (RTG) as discussed in our recent policy statement concerning RTGs, and the materials filed do not constitute an RTG Agreement as described in the policy statement...We will not afford ITCF decisions the special deference that we may be willing to give to decisions reached by an RTG." The FERC found that the ITCF did not contain most of the elements of an RTG such as:

- The ITCF makes no mention of how it will coordinate and consult with state regulatory authority or other authorities;
- Its members do not obligate themselves to provide transmission service to each other;
- Its geographic scope has not been shown to be efficient or sufficiently contiguous;
- While the ITCF establishes a Planning Committee, it does not appear to provide for a coordinated plan to meet the reliability and economic demands on the transmission system; and
- There are no termination provisions.

Robert Arnold, Chairperson of the ITCF and Executive Vice President for Power Supply at GPU Service Corporation will discuss the ITCF approach. (See Tab G for the text of the FERC's decision in the ITCF case.)

In New England, efforts to establish an RTG have collapsed. See white pages for an article describing the New England experience.

The Wisconsin Transmission Interface Study: A Model for Regional Electric Transmission Planning

A cooperative planning process, when pursued analytically and in good faith by utilities and regulators, can develop the information decision makers need. Everybody benefits.

Michael Arny

Decision makers seem to be between a rock and a hard place on transmission issues.

On the one hand, broad transmission access is the key to the more competitive power supply market that is developing. There are more players with an interest in transmission issues than ever before — from nonutility generators, to every sort of utility, to property owners and protectors of the environment. Increased interest in power purchases from remote sources has added players, since such arrangements have impacts that are regional in scope.

But the difficulty of siting transmission lines continues to increase as the public has concerns about environmental impacts of transmission lines, including electromagnetic field and their potential health effects.

Given these circumstances, decision makers need sound information to determine what transmission system improvements are really needed and the procedures to get these lines sited. How this can be accomplished?

Michael Arny *is systems planning coordinator for the Wisconsin Public Service Commission. At the Commission, Mr. Arny focuses on systems planning, including integration of interutility planning matters and supply/demand resource planning. Mr. Arny holds a B.A. and a B.S. and M.S. in mechanical engineering from the University of Wisconsin.*

Wisconsin's experience indicates it can be accomplished with careful planning in a framework that addresses both economic and system engineering concerns from local and regional perspectives.

Transmission planning is inherently complex, due to the interrelated, interactive, *organic* nature of the interconnected power system. Yet, with all this complexity, the information needed by decision makers is simple:

- Where and when are improvements needed to maintain reliability?
- Where and when may system improvements increase system efficiency?
- What are the relative costs, benefits, and environmental impacts of these alternative system improvements?

I. The Wisconsin Model

The transmission planning and siting process that has developed in Wisconsin has provided four significant benefits to decision makers:

(1) Much of the uncertainty about need for transmission system improvements to maintain reliability is resolved.

(2) The risk of not identifying potential reliability problems — particularly at boundaries between utilities and Reliability Councils — is reduced.

(3) The risk of not identifying the range of desirable alternatives for solving system problems is reduced. Again, this is particularly true at utility and reliability council boundaries.

(4) The costs, benefits, and environmental impacts of transmission system improvements to increase regional efficiency can be better evaluated.

In general, we have found that our planning process decreases the area of uncertainty — and discomfort — for decision makers by providing better information. The strength of the process is twofold: (1) it resolves many of the questions that can be resolved through analysis; and (2) it develops a good foundation of information for decisions on the tough questions that remain. This allows the decision makers to focus on these difficult questions with a more solid information base, affording a better chance to weigh and balance costs and benefits, environmental impacts, risks and uncertainties in choosing between alternatives.

Transmission planning is inherently complex, due to the interactive nature of the interconnected power system.

Finally, when deciding in whose back yard new transmission facilities should be located, the decision maker has significant assurance that the improvements are actually necessary.

This process could serve as a model capable of fitting the goals of decision makers in a variety of circumstances. The following outline of features of the method, as practiced in the most recent Wisconsin Advanced Plan, provides an indication of this potential.

A. The Model in Practice

The Wisconsin transmission planning process is carried out in the context of the state's 1975 siting law for major electric facilities. This law established a two-step, long-term planning and siting preapproval process for major electric facilities. The siting law applies to all such facilities, not just those owned by utilities, and is an open public process. Moreover, before facilities can be approved in a *construction* proceeding, they must have received planning approval in a *planning* proceeding.

Long-term plans are developed and reviewed on a three-year cycle. The long-term planning proceeding is a forum for determining future needs and alternatives available to address them.

In the construction proceeding the question of need is revisited and specific cost and routing questions are addressed.

The transmission planning process has evolved incrementally since the siting law was passed. In the 1986 long-term planning process order, the Public Service Commission added specific criteria for transmission planning.[1] The 1989 long-term planning order required Wisconsin utilities to develop and evaluate alternative plans for increasing transfer

capability. The order also specified the analysis to be carried out to evaluate transmission additions to increase transfer capability.[2]

B. The Institutional Setting

To understand the process, it is necessary to understand some of the ground rules that underlie it.

1. *Regional Setting.* Wisconsin utilities sit astride a seam between two NERC reliability councils — Minneapolis-based MAPP and Chicago-based MAIN. The eastern Wisconsin utilities are in MAIN; the western Wisconsin utilities in MAPP. There are nine Wisconsin utilities in all involved in transmission planning: five investor-owned utilities, one municipal utility, two municipal joint action agencies, and one generation and transmission cooperative. Four of these utilities serve significant amounts of load outside of Wisconsin or are operated on an integrated basis with an out-of-state parent company.

2. *Status of Planning.* The Wisconsin Interface Study was completed in the fall of 1991. Results were presented in the Sixth Wisconsin Longer Term Planning Proceeding; this docket is still open. A Wisconsin PSC decision and order are expected by early July 1992.

3. *Planning Approach.* The effort involves working groups of affected utilities, Public Service Commission representatives, and interested intervenors. These groups work cooperatively with each participant, making sure information is developed to answer questions each interest group believes are important. If there were disagreements about how to do the analysis, they would be taken to the Commission for resolution, but this is rarely necessary. Work of the groups includes the full range of planning development:

- Development and verification of the data inputs for modeling the system.
- Identification of questions the analysis should address.
- Selection of alternatives to investigate.

- Determination of information to be developed to support the comparison of alternatives.

These working groups provided the opportunity for early input of issues into the development of plans by nonutility as well as utility participants. (It is too late at the end of the planning process to get these questions answered without significant disruption.)

The working groups develop the information base for policy decisions on what transmission facility improvements would be required. They pursue an approach of building up from the bottom.

Analysis began with the development and review of input data. Transmission requirements were developed first for small areas and then for successively larger areas.

C. Elements of a Plan

The tasks for developing a regional plan can be broken down into the following steps:

- *First,* determine what facilities are needed for local area reliability.
- *Second,* determine how much transfer capability is inherent in the system developed for local area reliability.
- *Third,* develop transmission options to increase transfer capability to higher levels and determine the costs for each level.
- *Fourth,* determine the benefits of various levels of increased transfer capability.
- *Fifth,* investigate the environmental impacts of the various options.
- *Sixth,* lay out this information for a balancing of costs, benefits and environmental impacts and other factors by policy decision makers.

II. Purposes for Transmission Expansion

A. For Local Area Reliability

The basic approach to determining transmission needs for local area reliability is to carry out systematic, consistent analysis based on up-to-date information. For selected study years about 5, 10, 15 years out into the future, transmis-

sion system power flow models were developed. These models include all transmission lines 69 kV and above in the affected region. Enough of the surrounding system is included in these models to make the model accurate for the outages being addressed.

Using the power flow model of the transmission system, all possible single outages are checked for each study year to identify future problems. The total study area is divided into sub-areas, based on which problems are closely interrelated. For example, in developing transmission plans for eastern and western Wisconsin, 16 study areas were used. Alternative solutions to each problem were developed and tested to confirm that they solve the problems using the power flow model. Then, representative sets of solutions to the problem in all sub-areas were combined for each study year, with all possible single outages being tested using the system model to make sure that, in combination, these solutions solve all the problems for each year.

B. For Transfer Capability to Provide Regional Efficiency

1. *Developing Transmission Alternatives for Increased Transfer Capability.* This part of the analysis builds on the above determination of what transmission improvements are needed for local area support.[3] The system designed with the sole aim of providing local area reliability provides some level of transfer capability as a side benefit. The next step is to determine what facility additions would increase transfer capability to various levels.

First, a model of the regional transmission system is developed that includes enough of the system to provide accurate results. For the Wisconsin Transmission Interface Study, this model includes most of the transmission, generation and loads in the Midwest.

The transfer capability of the system with improvements needed for local area support was determined using this system model. (In the Wisconsin Transmission Interface Study this was 300 MW.) Then, a range of transmission addition options that use different approaches to increasing the transfer capability was developed.

An effort was made to develop a range of alternative approaches so as to provide a diversity of costs and environmental impacts. The alternatives developed included: three using additions of 161 kV or below; two using additions of 345 kV or below, and two using 230-250 kV AC or DC additions.

Each option was analyzed to determine how it can be developed in steps to provide the range of transfer capability that may be desirable. Transfer capabilities investigated in the Wisconsin Transmission Interface Study ranged from 300 to 2000 MW.

The costs of the transmission improvements necessary for each level of transfer capability were calculated for each option (Figure 1). Finally, the electrical losses of each option were calculated for various levels of transfer.

2. *Environmental Impacts.* Information on the environmental impacts of each transmission alternative was developed for use in decision making. This information was factored into decisions

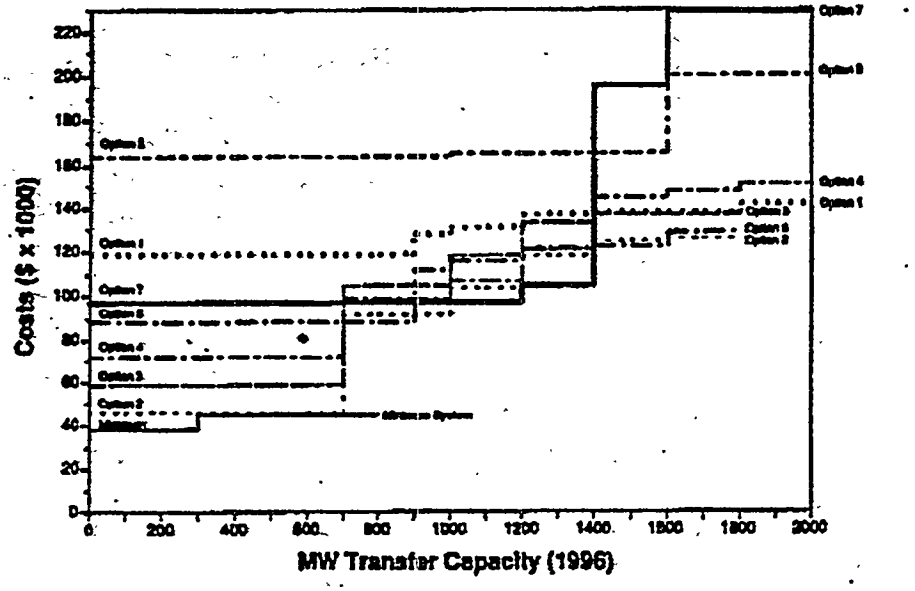

Figure 1: *This figure shows the construction costs (in 1990 dollars) for a range of transfer capacities for the seven options investigated. The transfer capacities used are those that would occur under 1996 conditions.*

on the appropriate level of transfer capability to develop and on which transmission improvement alternatives are appropriate for reaching such a goal.

3. *Benefits of Increased Transfer Capability.* For the Wisconsin Transmission Study, input data was developed for a multi-area production cost analysis model of most of the Midwest. Using this production cost model, the effect on regional production costs was calculated for a range of transfer capabilities between sub-areas. The Wisconsin Transmission Interface Study included seven sub-areas in the production cost analysis.

A generation system reliability model was used to calculate the benefits of increased transfer capability on generation system reliability. This addressed whether increased transmission transfer capability would allow the generation reserve margin to be lowered. In the Wisconsin Transmission Interface Study, no significant impact on generation system reliability was found.

Integrated Resource Planning (IRP) analysis is used to evaluate the net benefits of remote resources. The question here is: how does the long-term cost of the purchase of distant power resources plus the transmission required to import the power compare with the costs of local demand- and supply-side options? This IRP evaluation of capacity options was not included in the Wisconsin Transmission Interface Study because no utility identified remote resources it wished to consider during the study process. The issue may be analyzed in future, however.

4. *Net Benefits of Alternatives.* Based on the analysis of costs and benefits of increased transfer capability, the net benefits of each transmission option were calculated. The net cost reductions of the options developed in the study are shown in Figure 2.

A comparison of the relative environmental impacts of the alternatives was also prepared.

III. Orderly Decision Making: The Right Decision at the Right Level

Using information developed in the process, the relevant decision makers — both the utilities who must propose and the regulators who must act on their proposals — will determine when and where transmission improvements are needed to maintain reliability and enable economic efficiency. For both western Wisconsin (where this process has been conducted three times) and eastern Wisconsin (where it has been conducted twice), such decisions at the planning stage of the process have become quite routine. Typically, little or no disagreement about the problems or alternative solutions remains when the analysis is completed.

The extensive effort put into developing the plans pays off again, in that very little hearing time is needed to review them at the planning approval stage.

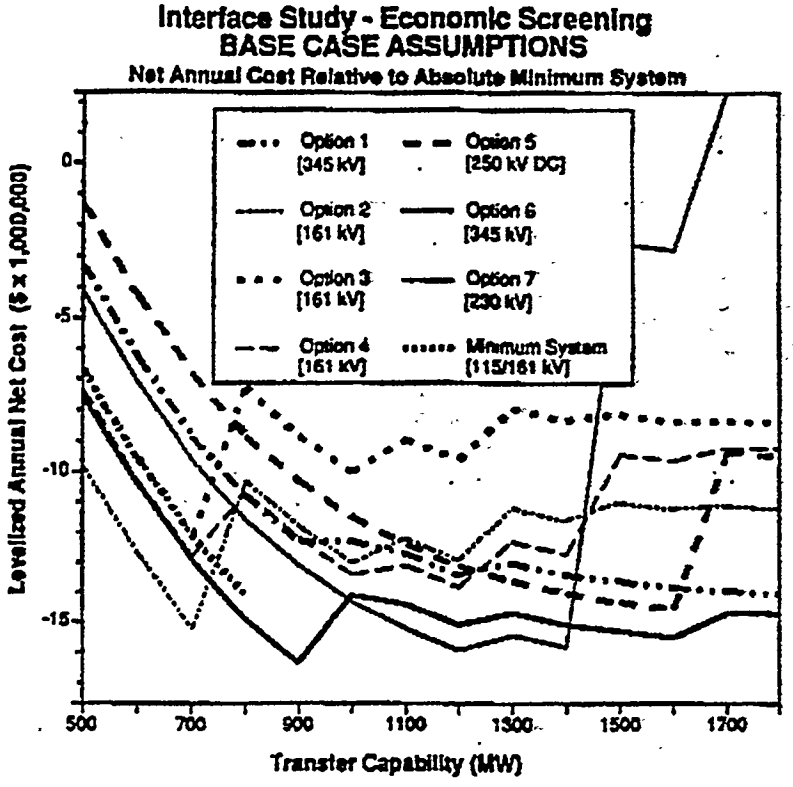

Figure 2: *Results of the Interface Study (base case assumptions). This figure shows the net levelized cost of each of the seven options for a range of transfer capabilities. Notice that most of the values are negative, indicating a net savings.*

In construction review proceedings, the extensive planning analysis pays off in several ways. First, it is extremely difficult to assess long-term transmission planning analysis effectively in a construction proceeding. This is true for several reasons. The construction proceeding is by necessity focused in scope and time frame; typically only (1) problems that need to be dealt with currently, (2) the proposed solution, (3) a few alternatives and (4) the region directly impacted are addressed. By contrast, planning requires identifying problems and developing alternate solutions for the long term, as well as investigating the interactions between the problems and solutions in neighboring regions. To do this in a construction review proceeding would be extremely cumbersome. Yet, without this planning information, the decision maker would be left in the dark on the fundamental question of whether the proposed project makes sense in a larger context over the long term.

The effort at the planning level to substantiate the need for transmission improvements also pays off at the construction review stage of the process. Less effort is necessary to address the "need" question and more effort can be directed toward the selection of the best alternative, the specific routing, environmental issues and land owner concerns.

Information developed under this process on costs, benefits and environmental impacts of alternatives provides the policy decision maker with a substantial foundation for making these difficult, multi-disciplinary decisions.

IV. Need for an Open, Integrated Process

An open process is critical to successful results. An open process allows the concerns of all interested parties to be identified early and addressed during the process. This approach develops the full range of necessary information for decision makers. In doing so, it reduces the risk of issues appearing as a surprise late in the process, when it is too late to address them effectively.

In developing transmission planning information, having the context of an IRP process to work from is also very important. Future system loads and generation additions are important inputs. IRP analysis can refine these inputs, assessing the relative balance of generation additions and load growth, as well as the full range of demand side and supply side options.

The merits of increased transmission transfer capability to allow purchases of distant capacity or generation cannot be evaluated without IRP analysis of this option relative to local demand side and supply side options.

V. Conclusion

The Wisconsin Transmission Interface Study is a model of a regional planning process that provides decision makers a foundation for making complex decisions about transmission additions needed for reliability and efficiency. This information is equally important to utilities and other transmission users, regulators, property owners impacted by transmission facilities and guardians of the environment.

The process involves the various stakeholders in the outcome and addresses their concerns. It lays out the costs, benefits and environmental impacts of the options. From such a foundation the decision maker can make informed choices. Without such an approach, it would be much more a game of darts — and a high stakes, chancy one at that. ■

Endnotes:

1. Wisc. Pub. Serv. Comm'n, Order in Docket 05-EP-4 (Advance Plan 4 Order), 1986.

2. In its 4th and 5th long-term planning proceedings the Wisconsin PSC ordered that an analysis of increasing transfer capability be carried out and specified how it should be carried out.

Wisc. Pub. Serv. Comm'n, Order in Dockets 05-EP-4 and 05-EP-5. (Advance Plan 4 and 5 Orders), 1986, 1989.

3. Interface Study: Summary and Conclusions, Technical Support Document D22a (filed with PSCW by Wisconsin utilities), Fall 1991.

REQUIEM FOR A Heavyweight

By Gordon L. Weil

Reeling from a one-two punch, a painstakingly negotiated regional transmission arrangement (RTA) for New England may be forced into an early retirement.

The arrangement, hailed by its promoters as a heavyweight contender for the 1990s, fell victim to retail wheeling and to the Federal Energy Regulatory Commission (FERC), whose decision on the Northeast Utilities/Public Service of New Hampshire merger may be a TKO. The RTA's handlers are currently examining its viability, and a promising career in New England may come to an end. A look back shows not only what time left behind, but how the "prizefighter" actually may stage a comeback.

Arenas of influence

When Connecticut-based Northeast Utilities (NU) proposed to absorb Public Service of New Hampshire (PSNH), many utilities raised concerns about such a merger's potential anticompetitive effects. Led by Commonwealth Electric/Cambridge Electric, Boston Edison, and Eastern Utility Associates (known collectively as "Eastern REMVEC"), complaints surfaced that the new utility would drop a "transmission curtain" across the region, enabling NU to control power transactions.

A chief concern was that the NU-PSNH merger could result in NU's controlling both access and pricing for most third-party wheeling transactions. Because it has more surplus capacity than any other utility in the region, NU could virtually force others to purchase from it simply by manipulating transmission. Such domination by a single utility could endanger the viability of the New England Power Pool (NEPOOL), a "tight" pool that depends on a high degree of coordination among its members.

Eastern REMVEC, while not opposing the merger, argued that it should be subject to conditions limiting its anticompetitive effects. They suggested that an RTA, an approach already under discussion, would effectively blunt the anticompetitive threat posed by the merger.

Settlement negotiations began in earnest in November 1990. The parties hoped to agree on an RTA that would settle the case before a FERC decision on the NU merger application could be issued. However, the complexity of the negotiations and the number of parties involved impeded an early resolution. When the FERC issued its decision in mid-1991, it endorsed the RTA and ordered NU to file a proposal with the NEPOOL Management Committee no later than six months after the merger was consummated. Negotiations moved ahead on the basis that the NU submission would, if possible, be the document to settle litigation over the NU tariffs, also ordered by the FERC, and related matters.

On February 1 of this year, NU filed the RTA, which all but a few parties had agreed to. The RTA was to become an amendment to the NEPOOL agreement and required an 85-percent majority for adoption. Based on the positions adopted by the RTA Negotiating Committee, such a majority appeared likely at the time.

Down for the count?

Then came the one-two punch that halted the RTA's transformation into a NEPOOL amendment and may ultimately end its career.

On March 29, 1993, the FERC issued its order on the NU transmission tariffs, proposed in compliance with the merger order. Barely a month later, on April 27, 1993, New England Electric Systems (NEES)— second in size only to NU in the region—announced it would not proceed with the RTA unless many key provisions, the result of difficult

negotiations under the chairmanship of its own representative, were stripped out of the proposal.

In a sweeping order, the FERC dealt with all aspects of the proposed NU tariffs. In tandem with other recent orders, the tariff order addressed many of the issues raised in the RTA negotiations. On many issues it came to a similar result or an alternative of similar effect. On some essential points, however, the order seemed to produce a significantly different result for NU, notably with respect to rates and tie lines. NU suggested that the RTA was a "done deal" and ought to be completed without change.

In response to the tariff order, which set apparently reasonable rates for NU transmission services, as well as to issues distinct from those raised in the order, NEES informed other parties that it could no longer accept an RTA that included a NEPOOL transmission rate or even a common method for determining rates. This announcement came as NEES was moving toward a more market-oriented policy designed to make it a major seller of transmission services.

The NEES announcement, reversing its early RTA approach, implied that the negotiators had become so immersed in constructing a balanced and open system that they had lost sight of the rapidly changing world around them. It became clear that NEES wanted to be an agent of change itself, and that the RTA no longer suited its plans. In particular, NEES seemed to want to assure itself of an opportunity to reap a significant return on transmission investment, especially in retail wheeling, that it might have been denied by the RTA rate rules, which would have kept it from setting its own rates.

Without NEES, there is no RTA. Consequently, all parties agreed to review the February RTA draft to determine whether what remained, after accounting for NEES's concerns, was of value to them. That review is now under way.

The draft RTA was perhaps the most ambitious regional transmission plan that could be prepared. Because of NEES's action, however, much of the debate that the FERC order promised to stimulate about the draft RTA was rendered moot.

Native loads

The RTA draft provided for transmission access and a rate mechanism covering a wide range of transactions within the region. It was clearly intended to require RTA transmission for wheeling entitlements necessary to meet capacity requirements. The National Energy Policy Act, enacted as the RTA negotiations came to a close, paved the way to such access, meaning that the access concerns raised by the NU-PSNH merger were largely resolved outside the RTA process.

Nonetheless, the draft agreement showed that RTA transmission could not be subordinated to native load on economic grounds. Firm RTA transactions would necessarily enjoy a high priority, because the purpose of the RTA was to recognize that the transmission system serves the native load of the various NEPOOL participants. In a sense, the RTA recalls former FERC Chair Martin Allday's dictum: "Everybody is somebody's native load."

Under the RTA, all NEPOOL utilities would provide transmission services to all other NEPOOL utilities. Essentially, New England would have an open-access transmission system for firm wheeling. In theory, sufficient transmission capacity exists in New England for all generation. As regional load grows, however, NU or other utilities could undermine full market choice simply by blocking new transmission. This situation would change with the RTA: If a utility declined to construct new transmission for use in third-party transactions, the NEPOOL Management Committee could move forward with new transmission by declaring that a Pool Designated Transmission Facility (PDTF) should be constructed.

Resolving one of the stickiest issues in the NU-PSNH merger litigation, the RTA provides that the portion of a new transmission line (or an entire line) designated as PDTF may not be used by the host utility's native load as it grows. This protects third-party wheeling customers from being pushed onto the margin and paying the highest transmission costs.

New England Electric turned against the RTA when it no longer suited its plans.

Special NEPOOL voting rules govern PDTF determinations to make it more difficult for NU and other large utilities to block new transmission. All of the decisions about new transmission will continue to be subjected to state siting agency authority. The RTA addresses only the utility aspect of new facilities, and environmental constraints continue to apply.

Assuring transmission access

While the Energy Policy Act and the FERC tariff order address new transmission facilities, the RTA goes farther in assuring that transmission access can be made a reality, even if a host utility has no need for the facilities. As the draft RTA is revisited, the PDTF is likely to remain an essential element, if the New England agreement is to have real value to the region.

Representatives of non-utility generators (NUGs) were involved in the negotiations, too, and parties were aware of the need to recognize their concerns, especially because most new generation likely will be developed by NUGs.

In bidding to sell power, a NUG would know in advance the cost of transmission, which it might account for

in pricing its bid to make it competitive with offers coming from sources closer to the purchaser's service territory. The RTA also would contain provisions assuring a NUG that, should it have a purchaser for its power, the host utility will provide the transmission necessary to link it to the PDTFs.

Perhaps the most important provisions for NUGs relate to premium payments at transmission interfaces. NUGs might normally expect to be asked to pay the entire cost of a new transmission facility required to move its power to the market, even if those facilities could only be built economically on a scale greater than any required by the new NUG. For smaller NUGs, the incremental cost could prove prohibitive. The PDTF mechanism would ensure that, in general, new users of a constrained interface would not have to carry the entire cost if they do not require the entire facility or if its costs are high. According to the draft RTA, some costs would be defrayed by all NEPOOL transmission users until the users of the specific interface fully use the new facilities. For upgrades that prove to be unusually costly, overflow costs may continue to be borne by all transmission users. Finally, if a later upgrade is required, the users of the first upgrade would be "vintaged" and thus protected from any higher rates associated with the second upgrade.

A level paying field

The draft RTA also contained a general antidiscrimination clause. RTA drafters intended to place all generation on a "level paying field" by having the buyer pay and by providing the same rules with respect to access and rates, irrespective of generating source.

In the draft RTA, issues relating to access to tie lines linking New England with other regions, including appropriate charges, were left largely unresolved. Despite the FERC's tariff order, NU was not required by the RTA to provide access to New York; the Energy Policy Act went further than the RTA in requiring access. In addition, the FERC order left many with the impression that tie access and pricing would be treated like any other NU transmission costs, with no guarantee that NU would receive opportunity costs at a level it expected. Thus, it is likely that these matters would be either left outside the scope of or addressed differently in a revised RTA.

Under current NEPOOL practice, unused tie transfer capacity produces tie benefits that result in a lower capacity requirement for each NEPOOL participant. Tie owners have long felt that the other participants should compensate them for the benefits derived from their ties. Many NEPOOL participants have also been unhappy with a system in which they can lose tie benefits simply because another utility has contracted for a transaction across one of the ties. When unused tie capacity is reduced, so are the associated tie benefits.

The RTA draft provides that tie owners be compensated for the tie benefits they produce for others, but only at the point (presumably after the end of the century) when such benefits are needed by a utility to meet reserve requirements. Paying for tie benefits was not, in fact, integral to the RTA, but became a part of the compromise. Many parties recognized that it is appropriate to pay for actual benefits received. (How this issue will fare is uncertain now that many elements of the RTA compromise will disappear.)

The RTA draft included an Outside Transaction Adjustment (OTA) to compensate other participants when a utility makes a purchase over the tie, which unilaterally reduced tie benefits distributed throughout NEPOOL. The general rule is that the NEPOOL participant making the transaction must "take the OTA hit" and ensure that others lose no benefits. This rule would have discouraged capacity transactions over the ties, although its potential effect would be reduced if the FERC considered the tie owners' loss of tie benefits as part of the opportunity cost calculation, subject to offset by added wheeling revenues.

Under the RTA, tie owners would receive a limited exemption from the OTA, provided they make transactions by August 1 for the ensuing power year. The issue of OTA exemptions can be expected to resurface if the RTA is revised.

Paying for tie benefits imposes a new cost on nonowners of ties, but some consider such a payment inevitable. The OTA stands to benefit all NEPOOL participants, but exemptions for the New York and New Brunswick tie owners tilt markedly in their favor and against the interests of others. The OTA exemption for New Brunswick Power, for example, benefits those who purchase from that utility, making it a privileged provider of nonregional capacity.

Transmission costs prove thorny

In many respects, and certainly in terms of time spent in negotiation, the most difficult RTA issue was how to determine transmission costs. This issue directly raised the question of parallel or loop flows. Traditionally, transmission has taken place by what is known as the "contract path method." No matter what path the electrons take, a wheeling transaction is deemed to take place along a path set by contract, the only limitation being that contract quantity cannot exceed physical capacity. Utilities whose systems are crossed by the flow contend that they should receive some compensation under a regional arrangement. While this position may be sound theoretically, it is difficult to implement.

The RTA negotiations were based on the concept of "rough justice," meaning that no utility should face a sharp up or down change in its net transmission budget because of the shift to the RTA. As a result, no transmission provider under the contract path method wanted to give up revenues, which required that transmission providers

on parallel paths be compensated with additional transmission revenues. Such compensation, in turn, raised the cost for transmission users, disrupting their own version of rough justice.

RTA negotiators tried to develop a wheeling matrix with sufficient modifications to provide rough justice. At times, the matrix took on the appearance of a Rube Goldberg contraption. After more than a year of effort, it became clear that a parallel flow system was elusive enough to torpedo any hope of reaching agreement on a timely draft that NU could file. As a result, the RTA reverted to the contract path method, but with an important modification: Each transmission provider would charge the NEPOOL Transmission Fund a rate determined on the basis of a "uniform rate methodology." In other words, all transmission providers would set their rates exactly the same way. To ensure that they did not depart radically from current rates in determining the elements of the regional rate formula, negotiators focused on the ultimate level of rates likely to result.

All transmission providers would set their rates exactly the same way.

While the FERC tariff order called some costs into question by excluding from NU's tariff major costs relating to Hydro Quebec transmission (costs that had been included in the RTA formula), the NEES announcement nullified all of these provisions. An RTA rate and a common rate method will not exist, and there is no longer any need to resolve the loop flow issue.

In its NU-PSNH order, the FERC said that if a utility built facilities to relieve a constraint, it might charge a transmission rate no higher than the embedded cost of its system or the incremental cost of the expansion. The embedded cost would presumably include the cost of new facilities, rolled in with other, preexisting transmission facilities costs. Thus, as a result of building new facilities, the embedded cost might increase. On the other hand, the cost of the new facilities might not increase embedded costs because the additional wheeling would carry such costs. In any case, if new facilities were required to relieve a constraint, the FERC decision would keep the wheeling customer at the margin, enabling the native load to push the third-party customer onto the new facilities while it continued to enjoy the embedded cost rate.

The RTA draft handled the situation somewhat differently, requiring a utility to add the cost of building new facilities to its embedded costs, which would be included in calculating the RTA revenue requirement. There was no provision for either lost opportunity costs or incremental costs to be recovered from the Transmission Fund. If NEPOOL were to construct PDTFs, the situation would change. The RTA base rate would have remained unaffected by the cost of the new construction, which would be paid by the users of the new facilities. Users would pay a base rate that would actually cover all the embedded cost of the utilities providing service. A "multiplier" of the base rate would be used to calculate compensation for incremental costs.

Critics of the RTA, a group that came to include NEES, found that contrary to the FERC order, the RTA would require payment of both embedded and incremental costs. Yet the base rate would have compensated the embedded cost of all New England systems used, not just those where the new construction took place. The multiplier compensates for the cost of the new facilities. Thus, the embedded rate would be lowered from the cumulative effect of the embedded rates of systems on the contract path, but increased to cover some of the incremental costs. To have a purely embedded retail rate, the RTA base rate would have to be high, and many transmission customers would have to pay for new facilities they were not using. In the alternative, the incremental rate would be so high as to create a disincentive to open access transmission.

If the PDTF is to be a part of a revised RTA, there will have to be an equitable method for recovering the costs of new facilities, one that will not serve to impede their construction. Because so many constrained interfaces in New England consist of facilities owned by more than one utility, the RTA appears to be the only place that payment for new facilities can be settled in a comprehensive and reliable manner.

Although the draft RTA moved only modestly toward a regional approach to transmission cost development, it was more advanced in developing a regional transmission rate. Essentially, the RTA uses a modified postage stamp rate method expanded with "multipliers"—to discourage premature demands for new facilities and to pay for them when needed—as well as "adders"—to maintain a degree of pancaking that existed under the system of individual transmission tariffs. Thus, the RTA rate system provides utilities with strong incentives to purchase power from neighboring utilities.

The rate mechanism was described in considerable detail in the draft RTA, but because of the NEES position all of these provisions must be dropped. There will be no RTA rate.

The New England RTA benefited from the pressures resulting from the NU-PSNH merger case as well as the tightly integrated nature of NEPOOL. The result, embodied in the February 1993 draft RTA, was a carefully constructed agreement as well suited to the NEPOOL

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environment as was possible to achieve in any reasonable period of time.

If RTAs are to provide more than a regional arbitration mechanism when it comes to rates, the draft RTA provided useful alternatives: a common rate method for all transmission providers and a single rate system for service. It included a means of sending price signals to transmission users that could forestall pressure on potentially constrained transmission facilities.

The draft RTA reflected a world in which regulation was paramount and limited access could distort power supply choices. The National Energy Policy Act and the increased role of the market in setting prices suggest that utilities will want the freedom to compete and will reorient their operations to survive and profit.

The lessons of the NEPOOL RTA are that new rules can help in achieving the objectives of the Energy Policy Act, but that the rules must not stand in the way of rate determination by the market. The RTA negotiations gave New England a better understanding of the potential of open access electric transmission, an understanding that can be used there and elsewhere in the new world of competition.

Gordon L. Weil is President of Weil & Howe, a consulting firm in Augusta, ME. He was one of the principal negotiators of the RTA.

Transmission Pricing

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Regional/Subregional RTGs in the West

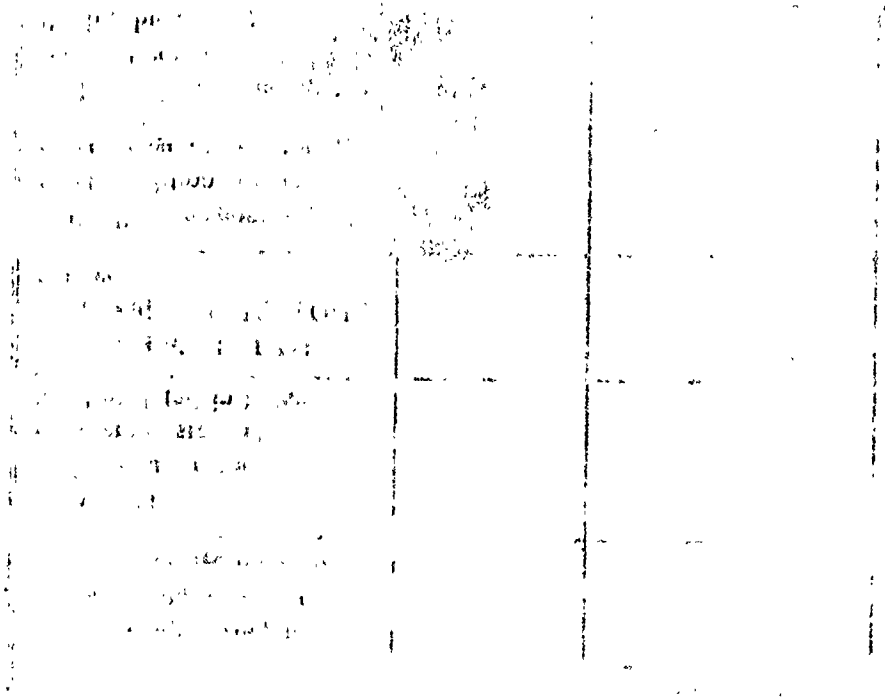
Western RTG discussions have raised many questions about whether to have one west-wide RTG, multiple RTGs or some combination of options, as well as the relationship among multiple RTGs. A range of options appear possible, from one west-wide RTG, to some type of hybrid of subregional RTGs and a west-wide RTG, to subregional RTGs which may or may not have reciprocity agreements. While the objective of avoiding any "seams" in the western system is widely held, it may be difficult for the parties to agree on an institutional mechanism (e.g., one west-wide RTG or subregional RTGs with reciprocity agreements) to avoid creating seams.

The industry panel will be discussing regional/subregional issues. The following table outlines some of the options and issues.

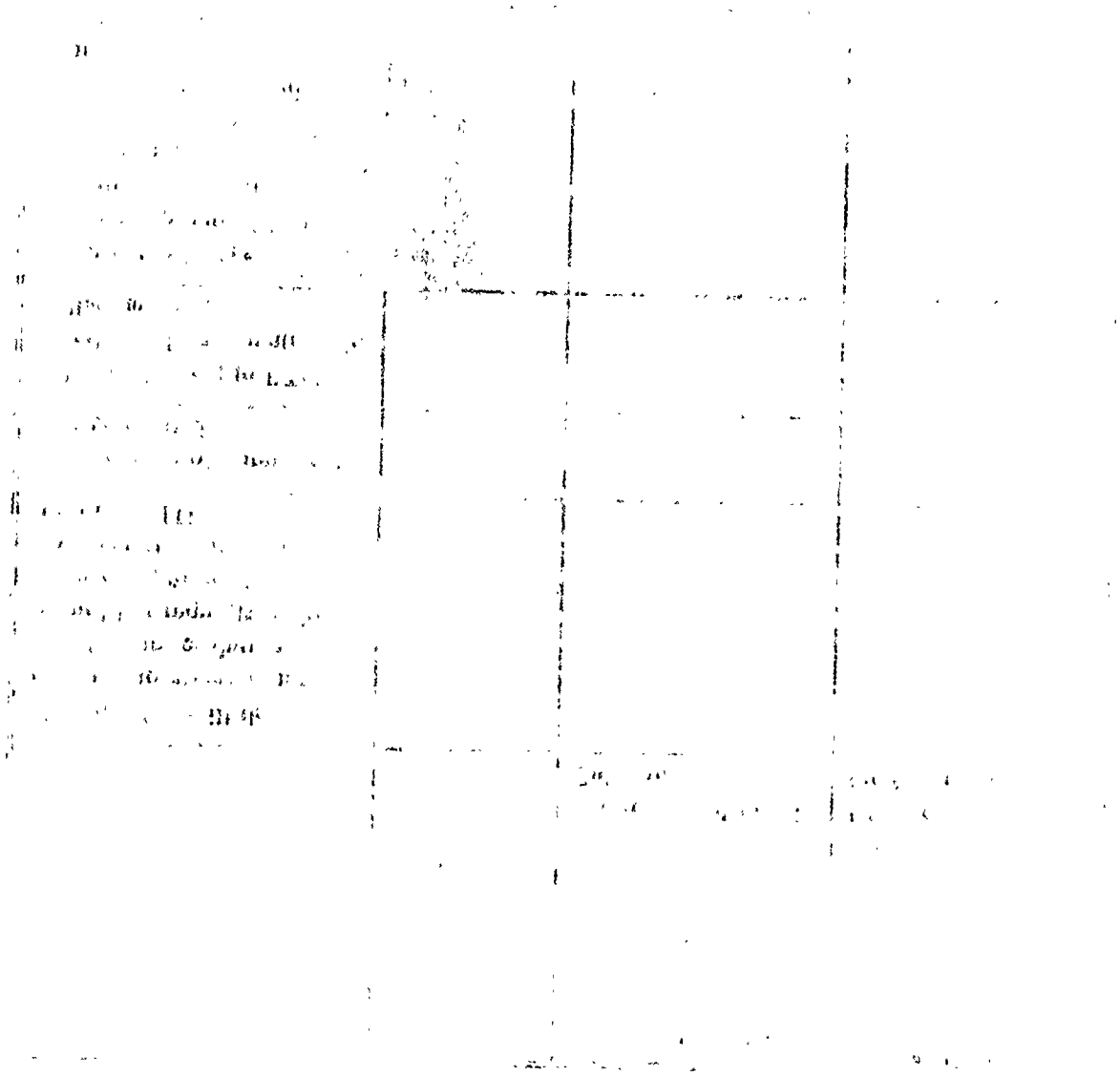
RTG Options

Issues	West-wide RTG Only	Hybrid of West-Wide and Subregional RTGs		Subregional RTGs Only	
		Umbrella and Fixed Subregional RTGs	Umbrella with Subregional RTGs Whose Geography Changes Based on the Current Issue	With Reciprocity Among RTGs	Without Reciprocity Among RTGs
Is agreement reachable? (What are the views of the various industry interests?)					
Is the RTG approvable by FERC (e.g., adequate geographic size, adequate level of detail in bylaws)?					
Who controls the RTG organization (TDUs, TOUs, IPPs)?					
Is the RTG responsive to local conditions (where most decisions are made)?					
Is the RTG responsive to regional conditions (where the big bucks are)?[1]					

[1] Assumedly the most significant economic gains from additional transmission are among regions of the West with diverse load and resource mixes.



Issues	West-wide RTG Only	Hybrid of West-Wide and Subregional RTGs		Subregional RTGs Only	
		Umbrella and Fixed Subregional RTGs	Umbrella with Subregional RTGs Whose Geography Changes Based on the Current Issue	With Reciprocity Among RTGs	Without Reciprocity Among RTGs
How quickly will the response to access requests and dispute resolution occur? For requests within the geography of the RTG? For requests which cross multiple RTGs?					
What degree of bureaucracy will be created?					
What is the cost to RTG members of participation (in dollars and time)?					
What is the RTG's relationship with WSCC activities (duplicative, separate functions, coordinated) in areas of access requests, planning, project analysis, reliability, dispute resolution?					



Transmission Planning

One of the key elements FERC has identified for an RTG is that:

> An RTG agreement should require, at a minimum, the development of a coordinated transmission plan on a regional basis and the sharing of transmission planning information, with coordination of the interconnected electric system on a grid-wide basis. An RTG agreement should provide mechanisms to incorporate the transmission needs of non-members into regional plans. An RTG agreement should include as much detail as possible with regard to operational and planning procedures.
>
> — *FERC Policy Statement Regarding Regional Transmission Groups*

Dennis Eyre of the Western Systems Coordinating Council will provide a short briefing at the beginning of this agenda item to outline how transmission planning has historically been done. (See following white pages for slides from a WSCC presentation to the September 30 industry RTG discussions.) Thereafter, the industry panel will be asked to identify the key planning issues and how they may be resolved. For example:

- What type of transmission plan is necessary to comply with the FERC RTG policy statement? Can the plan be in the form of a process to coordinate transmission activities? Is a physical facilities plan required?

- What is the relationship between transmission planning decisions and transmissions access/construction decisions? Who will decide the relationship? individual utilities? the RTG? FERC?

- What have been the optional approaches to evaluating transmission needs in the past —

  - Wait for an individual utility to construct something and then seek to coordinate the facility's operation with the rest of the system (e.g., WAPA's installation of phase shifters in the Four Corners area to protect itself from loop flow)?

  - Allow for competing transmission proposals (e.g., the Phoenix-Mead-Adelanto line versus the Palo Verde-Devers II line)?

  - Invite all parties to participate in a proposed project (e.g., Southwest Intertie Project)?

  - Adopt a central planning function (e.g., Wisconsin)?

- If a transmission request could be satisfied by the use of multiple transmission paths, who decides which transmission paths will be used? the requestor? the RTG? FERC? WSCC (assuming it will be identifying available capacity on various

transmission paths)?

- How will the conduct of transmission planning affect potential state policy objectives, such as achieving fuel diversity, expanded use of renewable energy, etc.?

- What opportunities are there for states/provinces to participate in planning activities? Do states/provinces want to participate? If states participate in planning activities, should they also coordinate regulatory reviews of proposed projects?

Western Regional Transmission Planning

3 Components of Planning

- Need / Benefit Analysis
- Project Development
- Reliability Assessment / Rating

1994 WSCC 10-YEAR BASE CASE DATA BANK SCHEDULE

CASE	DATE DATA REQUEST MAILED	DATE DATA DUE TO AREA COORDINATOR	DATE DATA DUE TO STAFF	DATE PRE-RUN CHANGES DUE	STAFF MAILING DATE	DATE COMMENTS DUE TO STAFF
94 LS1-OP	08-20-93	09-17-93	10-22-93	11-16-93	11-30-93	12-28-93
95-96 HW3	12-10-93	01-07-94	02-11-94	03-08-94	03-18-94	04-15-94
94-95 HW2-OP	01-07-94	02-04-94	03-11-94	04-05-94	04-15-94	05-13-94
96 LS2	02-04-94	03-04-94	04-08-94	05-03-94	05-13-94	06-10-94
97 HS3	03-04-94	04-01-94	05-06-94	05-31-94	06-10-94	07-08-94
97-98 HW2	04-01-94	04-29-94	06-03-94	06-28-94	07-08-94	08-05-94
98 LA1	04-29-94	05-27-94	07-01-94	07-26-94	08-05-94	09-02-94
99 HSP1	05-27-94	06-24-94	07-29-94	08-23-94	09-02-94	09-30-94
00 HS2	06-24-94	07-22-94	08-26-94	09-20-94	09-30-94	10-28-94
02-03 LW1	07-22-94	08-19-94	09-23-94	10-18-94	10-28-94	11-29-94
95 HS2-OP*	08-19-94	09-16-94	10-21-94	11-15-94	11-29-94	12-28-94
04 HS1	09-16-94	10-14-94	11-18-94	12-13-94	12-28-94	01-20-95

* FIRST CASE OF 95 STUDY PROGRAM.

Need / Benefit Analysis

- RPPC Initiative
- Requires demonstration of impact on efficient use of resources
- Production Simulation -
  Prototype is WRL&R (MAPS) Study
- Capability in WSCC - 1994

Project Development

- RPPC Initiative & TFORP Guidelines
- Projects address regional needs and efficiency
- All prospective participants have opportunity to join planning
- Visible to all stakeholders

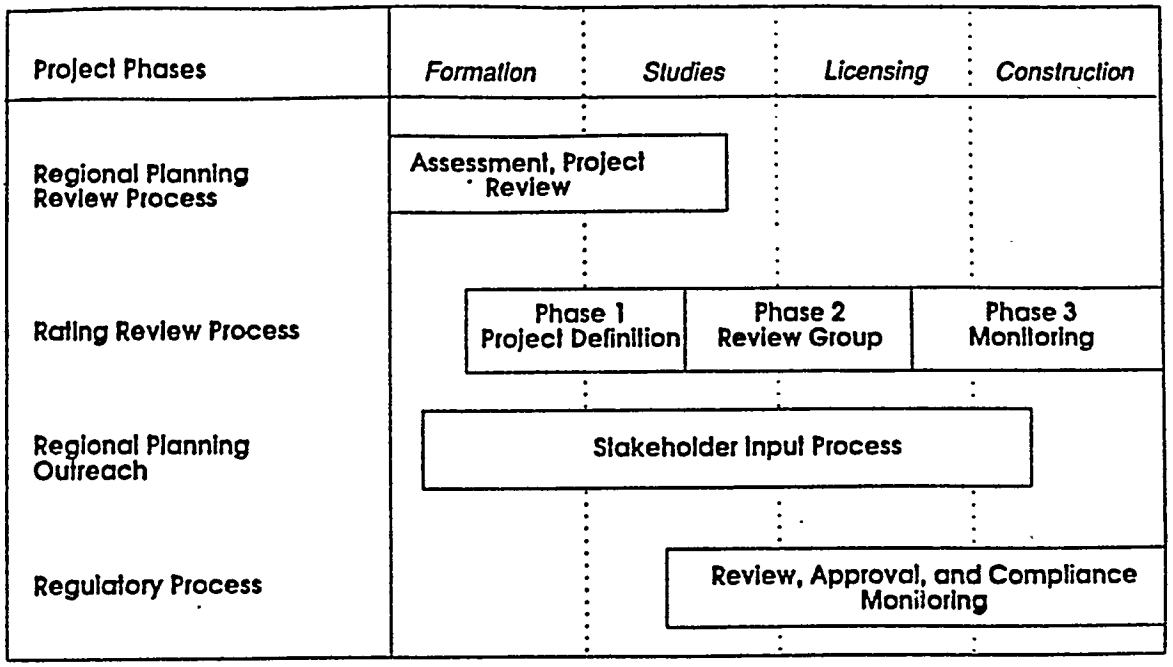
PCC Approval

Proposal Requires:

1. Consider future needs of others.
2. Consider alternatives which increase regional value.
3. Discuss corridor selection.
4. Demonstrate improved efficiecy in use of resources.
5. Identify operational constraints created or removed.
6. Discuss outreach coordination.
7. Discuss why not upgrade existing system.
8. Demonstrate coordination with other proposed projects.

PRESENT STATUS (WSCC)

Regional Planning and Project Rating Process



Reliability / Rating

- In place since 1992
- Based on criteria limiting impact on neighbor systems
- Extensive analysis of simultaneous and non-simultaneous conditions

Reliability / Rating

3 phase process:

Phase	I	II	III
Activity	Development	Rating	Construction
Study	Independent	Peer Review	Monitor
Result	Planned	Accepted	Operation

Reliability / Rating

- **Culminates at PCC**
- **Process applicable to Subregional groups**

Other Issues

Several other issues have been identified for discussion at the workshop.

The role of the federal power marketing administrations (Western Area Power Administration and the Bonneville Power Administration) in any RTG. Special language in the Energy Policy Act applies to BPA. BPA and WAPA have been invited to the workshop to discuss their participation in a western RTG(s).

The role of Canadian and Mexican utilities in the western grid. Such utilities are not subject to FERC jurisdiction. The draft bylaws of the Western Regional Transmission Association provide that, "Canadian or Mexican Transmission Providers may establish prices based upon policies different than, but no less favorable to transmission users, than those established by the FERC" (Section 10.1) and "Transmitting Utilities in Canada or Mexico may rely upon pricing policies of regulatory bodies other than the FERC if such policies are not less favorable to Transmission Users than those of the FERC." (Section 11) Kashi Mattu of POWEREX will discuss Canadian utility participation in an RTG.

The issue of **participation by western states/provinces in RTGs** has arisen at the west-wide RTG discussion. An early draft of the Western Regional Transmission Association bylaws provided for voting membership by states. The current version provides for ex-officio membership by "Commissions" defined as "State or provincial utility regulatory commissions or energy commissions." (Section 2.6) Under WRTA bylaws, "Commission Members shall select three Directors to serve in an ex officio status on the Board. Such ex officio directors shall be invited to attend and participate in all meetings of the Board, and Committees, but shall not have the right to vote on matters coming before the Board or Committees." (Section 5.2) WATSCO bylaws provide that "Representatives of appropriate regulatory and/or government agencies may be ex officio members of the Board of Directors and the Planning Committee. The Board of Directors shall designate from time to time no more than two representatives from such regulatory and/or government agencies from each State in which a member is subject to such regulatory and/or governmental agency to be ex officio members of the Board of Directors and the Planning Committee. (Section 8.12) FERC's RTG policy statement says, "An RTG should provide for a means of adequate consultation and coordination with relevant state regulatory authorities. State participation is encouraged."

Workshop participants will be asked to identify other important RTG issues.

State/Provincial Discussions

In the final section of the workshop, state and provincial representatives will discuss what, if any, actions should be taken on RTG issues, including potential responses to the FERC on its transmission pricing inquiry (comments are due November 8). Several states are developing comments on the transmission pricing issue. Enclosed are draft comments from Washington State. Others are encouraged to bring 40 copies of their draft comments.

STATE OF WASHINGTON

WASHINGTON STATE ENERGY OFFICE

925 Plum St. SE, Town Square Bldg #4 • PO Box 43165 • Olympia, Washington 98504-3165

October 11, 1993

Mr. Douglas Larson
Executive Director
Western Interstate Energy Board
VIA FAX

Subject: Preliminary Staff Draft Comments re: FERC Notice of Inquiry on Transmission Pricing

Dear Mr. Larson:

Enclosed is a preliminary staff draft of comments on the Federal Energy Regulatory Commission's (FERC) Notice of Inquiry on Transmission Pricing. Our staff has had several discussions concerning transmission pricing issues, which have resulted in the production of this draft. However, these comments have yet to be formally approved by the Energy Office or any other Washington agency.

We understand that the issue of transmission in general, and pricing in particular, will be the subject of the Monterey meeting in October. Bearing in mind the preliminary nature of these comments, we would be happy to have Western Interstate Energy Board (WIEB) circulate them for comment by other WIEB members.

Jim Harding of our office will be attending the WIEB meeting and would be happy to make a brief presentation summarizing these comments, if you so desire.

Sincerely,

Judith Merchant
Director

JM/jh/ay
O-L3-96W

Enclosure

cc: Dick Casad, Washington Utilities and Transportation Commission
Jim Harding, Washington State Energy Office

Preliminary WSEO Staff Draft 10/11/93

[Joint] Comments of Washington State Energy Office [and ?...] Regarding Transmission Pricing Policy

The Washington State Energy Office (WSEO) is pleased to provide comments on the Federal Energy Regulatory Commission's (FERC's) inquiry on transmission pricing policy. The WSEO's mandate is to assist state energy decision makers in acquiring and operating cost effective energy resources, consistent with environmental and other interests and with the regional power plan developed by the Northwest Power Planning Council. These comments accordingly focus on transmission pricing issues that have the potential to affect the acquisition, siting and management of energy resources in the State of Washington and the Pacific Northwest region. These include issues raised by questions 1, 3, 4, 6, 20, 21, 22, and 23 of the FERC Staff Discussion Paper, as well as an additional question raised in the Commission's inquiry that the Discussion Paper did not cover.

Summary

These comments make the following main points:

- It is federal policy to promote the development and operation of a mechanism that considers transmission, generation and demand side management as interrelated pieces of a comprehensive energy delivery system. The Commission has an opportunity to develop transmission pricing policies that encourage not only efficient building and operation of transmission, but also efficient building and operation of all electricity facilities and services.

- Pricing based on incremental or embedded cost of transmission *alone* will not provide an incentive for planning and operation of a comprehensive energy delivery system.

- FERC should adopt a pricing policy that considers not only the impact of transmission on existing generation but also on comprehensive energy delivery systems. Prices should also reflect the environmental and other impacts of transmission-related facilities. For example, a broadly-based "opportunity cost" pricing policy could influence the planning, siting and operation of generation and transmission resources. The Commission should continue its policy of examining opportunity cost pricing proposals on a case-by-case basis. The Commission should take into consideration the unique geographic, demographic, historical and institutional features of each generation and transmission system in examining any proposed opportunity cost pricing proposal for utilities or power marketing authorities (PMAs).

- Currently, FERC may set transmission rates for privately owned transmission lines under sections 205 and 212 of the Federal Power Act (FPA). In the Northwest, it also approves rates filed by the Bonneville Power Administration (BPA) under the Federal Columbia River Transmission System and Northwest Power Acts and makes findings of reasonableness for BPA's wheeling rates under section 212(i) of the Federal Power Act.

FERC should apply uniform principles for all transmission rates ordered or approved in the Northwest, regardless of the section or Act under which they are authorized.

Introduction

Before turning to the specific questions raised by Staff and the Commission, we would like to set the stage by presenting our view of some of the key transmission issues that are facing our region and the nation.

1. Advantages of a comprehensive transmission/generation/demand side energy delivery system.

The Staff Discussion Paper notes at the outset that "it is important to provide transmission price signals that accommodate the efficient operation of existing generating plants while also encouraging least cost investment in new plants." This principle is also reflected in the National Energy Policy Act (NEPACT). Section 722, which amends section 212 of the Federal Power Act, requires that Commission wheeling orders "promote the economically efficient transmission *and generation* of electricity." In our view, the importance of this principle cannot be overstated, and is not adequately explored in the Discussion Paper.

Transmission, generation, and demand side resources need to be considered together as pieces of a comprehensive energy delivery system, because their existence and operation are interrelated. For example, siting of generation and demand side resources has the potential to affect the transmission grid in either beneficial or detrimental ways. Most obviously, the siting of a new generation facility has an impact on transmission because it adds to the power that must be transmitted over the grid. (This impact can add to transmission constraints when the new power is flowing in the same direction as existing load; it reduces transmission constraints when the new power is flowing in the opposite direction.) In addition, generation can be dispatched "out of order" to relieve a transmission constraint at peak times or when units are out. Out of order dispatch refers to the circumstance where generation dispatched to relieve the constraint may be more costly to operate than some other generation plant.[1]

The need for development of a comprehensive energy delivery system that includes transmission, generation and demand side resources as a single mechanism has always existed. It is becoming increasingly important for two primary reasons. First, utilities historically had control over both the transmission grid and generation resources because they owned both.[2] Utilities could therefore consider siting and sizing impacts of new generation on the transmission grid, and conversely could plan and site transmission to meet the needs of load and planned generation. With the increase of independent power producers (IPPs) and exempt wholesale generators expected as a result of the enactment of NEPACT, utilities may gradually lose the advantages of being able to control siting and sizing of new generation and the matching of new resources with the grid.

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[1] See Northwest Utilities Service Company, 58 FERC ¶ 61,069 at 61,167 (1992)

[2] In the Northwest, BPA owns transmission associated with delivery of the Columbia River hydroelectric system, which is centrally dispatched by a consortium of utilities and BPA.

Second, and at the same time, increasing concern over environmental impacts of transmission lines has made siting of new lines exceedingly difficult.

Transmission pricing can play a crucial role in sending signals to utilities and others about the benefits of the development and implementation of a comprehensive energy delivery system. The Staff notes that the historic prevalence of "bundled" power transactions, where a utility or independent power producer (IPP) sells a packaged service of transmission and generation, "allows the parties to share the benefits associated with the sale of a bundled generation and transmission service." Although the Discussion Paper does not spell out these benefits, presumably the Staff is referring at least in part to the advantages of comprehensive energy delivery systems. We concur with Staff that these benefits must not be lost in any pricing policy adopted by the Commission. In fact, FERC should actively pursue pricing policies designed specifically to further comprehensive energy delivery systems. A "broad opportunity cost pricing" policy such as we describe further below in response to question 6 is an example of one such policy. Others may exist.

2. Differences between electric transmission system and natural gas pipeline industry.

The Commission has made significant progress in revolutionizing the natural gas industry's delivery mechanism in a series of historic orders culminating in Order 636 in 1992. We commend the Commission for undertaking a similar review of the electric delivery mechanism at this crucial point in time when access to the transmission grid is becoming increasingly significant, and at the same time increasingly difficult.

Electricity is different from natural gas in some significant ways, both physical and institutional. Physically, the electric system is different in at least three ways.

First, the electric grid does not generally contain the valve and switch system to direct the flow of energy that is more common in the natural gas network to direct the flow of energy. William Hogan notes in his Electricity Journal article that

> by and large, the electric grid was built purposely without "valves" to capture the huge reliability benefits that come from allowing nature -- not contracts -- to manage the flow.[3]

As noted in the Staff Discussion Paper, there are instances, for example in the Southwest, where phase shifters have been installed to redirect the flow of current and prevent instability of the grid. However, these phase shifters have reduced the interconnectedness of the Western grid and therefore reduced the number of economic transactions that are possible amongst Western utilities.

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[3]Hogan, W., "Electric Transmission: A New Model for Old Principles," Electricity J., March 1993.

A second difference between gas and electric utilities relates to stability. The Western transmission system, for example, consists partly of a few large and long transmission lines connecting urban centers. This type of system is unstable -- that is, the loss of one line can create failures of other parts of the system. Accordingly, the Western Systems Coordinating Council has developed a rating system that rates transmission lines not only by their thermal capacity but also by their ability to carry the load of other lines on the grid when those lines are incapacitated. For this reason, the existence of lines that are either oversized or undersized relative to neighboring transmission lines can create significant diseconomies. (For example, a line with a thermal rating of 500 MW might be rated at only 100 MW if the only "backup" line available had a thermal constraint of 100 MW.)[4]

A third difference between gas and electricity is the ability of generation or load management to substitute for transmission when transmission is constrained. As discussed above, with proper planning, generation can be sited and sized in such a way that it can be dispatched to relieve or prevent a transmission constraint, thereby avoiding the necessity of building transmission to meet an extreme peak load or meet all possible contingencies.

Finally, the transmission grid is institutionally different from the natural gas system in that on the whole, retail utilities own transmission (there are exceptions, most notably the federal Power Marketing Authorities).

For all of these reasons, we concur with Hogan's observation that:

> Electric transmission grid interactions and the associated congestion that remain hidden in the operations of the vertically integrated firm become a significant obstacle to full transparency, unbundling, comparable service, and successful competition in the rest of the electric market. Far more than for natural gas or telecommunications, therefore, it remains a challenge to design transmission pricing, access and investment rules ...

We would go somewhat further than Hogan and state that the continued existence of a reliable, interconnected, comprehensive, integrated electric delivery system is in the best interests of the United States. Federal transmission pricing policy should recognize the advantages of the current system and contain incentives to improve it.

3. Compatibility of Unbundling and Competition with Comprehensive Planning

As Staff has noted, the Commission's inquiry is timely, given the increased role of competitive forces in energy generation and NEPACT's mandate that access be made available to all at reasonable prices. Some commentators have observed what they consider to be a conflict between the provisions of NEPACT relating to integrated resource planning, and those provisions that encourage greater competition among energy providers. These observers believe that competition is fundamentally inconsistent with centralized planning.

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[4]The development of new technologies such as thyristor-controlled series capacitors has the potential to alleviate this problem considerably, thus "freeing up" much of the stability-constrained transmission in the region.

We disagree. Indeed, we believe that only with comprehensive energy delivery planning can competition work to the advantage of end users of energy. One model that has proved successful so far is the competitive bidding model adopted by many utilities. In competitive bidding, there are a number of bidders to supply energy services, but the ultimate choice is made by a single decision maker (e.g., a utility or a regulator), who considers the impacts of new entrants on the entire energy delivery system.

There is also concern that unbundling transmission services may lead to diseconomies because "a utility providing unbundled transmission service may be fully compensated for its transmission costs, but it does not receive any share of the possibly much larger benefits associated with the power sale."[5] Staff appears to be echoing our concern that pricing based on cost of transmission facilities alone does not capture the benefits of integrating transmission, generation, and demand side resource planning. We would share Staff's concern over the impact of unbundling if we believed the effect of unbundling were necessarily to remove the incentive to capture these benefits. We do not comment on whether the increased prevalence of unbundling transmission services is good or bad per se. We think it is possible, however, to design unbundled transmission prices that reflect the benefits of comprehensive planning and operation. We will offer one such methodology in response to Staff question 6 below.

4. Comprehensive energy delivery mechanisms should be designed and executed on a regional level

We have advocated here that FERC should establish pricing policy and approve individual rates that offer an incentive to plan, execute, and operate a comprehensive energy delivery system that fully takes advantage of the synergies among transmission, generation and demand side resources. The planning, execution and operation of the energy delivery system should take place at the regional level, preferably by the utilities and independent power producers who are directly affected by additions to system demands. Regional planning should be carried out in a responsible and reliable fashion, and should be able to provide evidentiary support for prices that are consistent with the regional plan.

The Northwest Power Act of 1980 established the Northwest Power Planning Council, whose responsibility was in part to develop a "general" regional plan for the Northwest states. To date, however, the Council's plans have not addressed either transmission concerns or the impact of siting and operating specific plants on regional interchanges and operations. Nor does any other regional body currently engage in review of specific generating plants or demand side resources to determine whether they are optimally sized and sited to meet the needs of the regional grid. The WSEO believes that the time has come to include some regional generation and demand side resource planning that considers the impact of these resources on the regional transmission grid and facilitates economic exchanges. If done correctly, FERC can then approve prices for transmission that provide signals that are consistent with the provisions of the regional plan. Whether this planning function is performed by RTGs, the WSCC or some other body need not be determined at this time.

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[5]Staff Discussion Paper at 3.

With these initial comments and conclusions, we turn to the questions raised in the inquiry and staff comments.

Response to Staff Questions

Question 1: Comment on Staff's proposed criteria for assessing transmission pricing reform.

The WSEO agrees with Staff's proposed criteria for assessing transmission pricing reform. We would add the following criteria, which we believe are consistent with existing federal statutory authority and/or policy:

First, transmission pricing policy should promote efficient planning, siting, use of and investment in *all* energy resources, not only transmission resources. This is consistent with the Staff's statement in the introduction that "it is important to provide transmission price signals that accommodate the efficient operation of existing generating plants while also encouraging least cost investment in new plants." This is also consistent with the transmission pricing policy enunciated in section 212 of the FPA as amended by NEPACT which requires that prices for FERC-mandated wheeling "promote the economically efficient transmission *and generation* of electricity" (emphasis added).

Second, transmission pricing policies should reflect the environmental and other external costs of new transmission siting and operation. Currently, the environmental impacts of new lines are considered qualitatively at most, for example in environmental impact statements prepared for entities required to comply with the National Environmental Policy Act. Transmission pricing policy that reflects environmental impacts of new transmission, or of operating existing transmission and generation differently would provide a means of compensating wheeling utilities for the environmental impact of building and operating transmission and generation. This pricing policy also would provide a price signal to utilities and other transmission customers of the "true" cost of transmission. In assessing the environmental cost of transmission siting and operation, FERC should defer to state or regional assessments of environmental cost of energy resources.

We will elaborate on these two points further below.

Question 3: Does the Commission's current pricing policy compensate the transmitter for all incurred costs? If not, what elements or cost factors are missing?

The Staff comments discuss a number of ways in which the current "postage stamp" transmission pricing policy may fail to compensate the transmitter for all incurred costs. Staff's comments focus on two of these ways: first, the either/or issue; second, the contract versus parallel path pricing issue.

Both issues focus on the extent to which alternative pricing schemes fully compensate for the direct cost of transmission lines. However, simply providing signals through prices to increase the utilization of existing transmission capacity or add new transmission may improve the

efficiency with which capital is used, but it could aggravate other conditions, such as generation limitations or environmental impacts if inefficient energy use is encouraged. Thus, there are at least two additional "costs" touched upon but not fully discussed by the Staff Discussion Paper that we would like to emphasize.

1. Cost of generation and demand side resources incurred as a result of providing transmission services. The Staff notes on page 5 of the Discussion Paper that there is a connection between transmission and generation in that a utility may be required to run generation units "out of order" in order to satisfy the needs of third party transmission customers. Utilities may also have to forego economic purchases or sales of power in order to accommodate transmission customers. This issue is not adequately explored in the Discussion Paper.

The Staff terms these "out of order" transactions "uneconomical." However, as pointed out by William Hogan in the Electricity Journal article cited by the Staff[6], economic dispatch needs to consider congestion costs on the transmission system as well as power plant variable costs. Out of order dispatch to relieve transmission constraints is "economic" if it is cheaper than relieving constraints by building new transmission.

Hogan argues that only a "tight power pool" with central dispatching capabilities (such as NEPOOL) can take advantage of the economic opportunities presented by strategic out of order dispatch. The Western grid does not plan and operate a tight pool. However, it is possible that strategic siting of generation or load management can operate to relieve transmission constraints in other ways. For example, siting a generating plant near load (so-called distributed generation) would obviate the necessity of building a transmission line from a remote generator to the load. In addition, a load management program or other type of "dispatchable" conservation program could also alleviate transmission constraints. Conversely, planning and siting of new generation or demand side resources without considering the impact on transmission can have detrimental impacts on transmission planning and operation. For these reasons, the Department of Energy, the Electric Power Research Institute, and others around the nation have begun to recognize the importance of incorporating transmission and distribution into the entire integrated resource planning effort of utilities and other planners. (see Department of Energy, Draft Five Year Integrated Resource Program; "The Vision of Distributed Generation," EPRI Journal at 8 (April/May 1993))

Although we agree with Dr. Hogan that transmission and generation should be planned in an integral fashion, we do not agree that only centralized dispatch can take advantage of these synergies. Provided that generating and demand side resources are planned and sited to take full advantage of the transmission grid, and that in turn the transmission grid is planned and sited to take advantage of generating and demand side resources, many of these synergies will occur even in the absence of central dispatch.

Thus, impacts of transmission services on generation and demand side management (and vice versa) are not only a "cost" incurred in wheeling but in many cases are an economic alternative

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[6] Hogan, Ibid.

that deserves greater recognition. We will suggest one way in which these costs could be reflected in transmission prices further below.

2. Environmental and other externalities. Siting of new transmission (and other related resources) to meet the needs of transmission customers has indirect impacts on the population, including electromagnetic fields, wildlife impacts, aesthetic impacts, noise, etc. Indeed, it is becoming increasingly difficult to site new transmission facilities because of these impacts. To a certain extent the complex permitting process often necessary to site new facilities internalizes these impacts. Even when facilities have been sited, however, there will be certain residual impacts that have not been mitigated through the permitting process.

The Bonneville Power Administration (BPA) incorporates environmental "values" in its cost-benefit analyses of new transmission lines. (See, for example, the Draft Environmental Impact Statement for the Non-Federal Participation in the Third AC Intertie.) However, it is unclear whether these values will be incorporated into pricing proposals. Doing so would help to signal to transmission customers the full cost of the service being provided.[7]

Question 4. How does the unbundling of transmission service affect incentives?

The key issue in any unbundling is the definition of the new unbundled services. They must be unambiguous and measurable. The buyer and seller must be able to agree on the quantity, quality, and terms of delivery; the services agreed on must be technically deliverable; and agreements must be enforceable. For unbundling to be beneficial, different customers should desire different combinations of the services being unbundled and the unbundling should allow for more efficient pricing, where services provided are priced close to their marginal cost and investment costs are borne by those whose actions cause the investments to be made.

The unbundling of city gate natural gas sales into wellhead sales and transportation and the further unbundling of transportation into transportation service and capacity are good examples of how unbundling should work. These services replaced the bundled service of delivered gas, priced more or less at average cost, with the unbundled services of undelivered gas, sold at market price, delivery, priced more or less at marginal cost, and capacity, with the capacity owner responsible for total cost but able to resell in a secondary market. The goals in this case were to avoid uneconomic pipeline expansions and increase off-peak utilization. The evidence so far shows that those goals are being achieved.

Whether successful or not, the unbundling of natural gas pipeline services is a poor model for the unbundling of electric transmission services. For physical reasons, it is impossible to define point-to-point delivery capacity or the point-to-point delivery services being provided to any one transmission customer without fully specifying the services being provided to all other customers. An end use load places load on all generation on the system, not just the generation

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[7] We will not address in this forum the problem of ensuring that the affected population is compensated for the environmental impacts of transmission and related resources. A number of suggestions for dealing with this have been made in the extensive literature emerging on environmental externalities of energy resources.

contractually obligated to serve that load. Power flows from each generating plant to each load along all closed circuits, not just a contract path. Power plant operators are unable to distinguish in real time between an increase in load due to a utility's own customers and an increase in another load it has no contractual obligation to serve.

It may be possible to define electric transmission services in a way that unbundling those services from generation and from each other is desirable and practical. However, WSEO has not yet seen a concrete proposal that we find appealing. Hogan's contract network, unified ownership of the transmission grid by a party that also serves as the auctioneer in a dispatch market, or another institutional framework may be desirable end-points, but bear little resemblance to the current situation. Getting from where we are today to a desirable unbundling outcome will require determining all parties' rights, ownership, and responsibilities under the current system, finding a desirable redefinition of those rights and responsibilities, and finding a system of compensation that will induce everyone to move from where we are now to where we want to be.

Unbundling of electric transmission services that meets all the requirements outlined above would provide incentives for more efficient use of existing transmission and generation and for more efficient choices about future transmission, generation, and demand-side resource investments. Unbundling of electric transmission services that is based on an inappropriate model would continue or increase incentives for inefficient investments, inefficient use of the existing system, and the shifting of the costs of long-distance power transactions to third parties.

Question 6. Does the Commission's opportunity cost pricing policy as articulated in* NU *and* Penelec *provide adequate incentives to the provider of the wheeling service?

The notion of "opportunity cost" pricing recognizes that wheeling power for transmission customers has impacts on the generation and other energy resources of the utility. We agree with FERC's prior rulings that FERC should review opportunity cost pricing on a case by case basis. FERC should, however, establish as a general policy that it will use opportunity cost pricing to further the goals of comprehensive least cost energy delivery systems in addition to the goal of holding native load customers harmless (the expressed goal in Penelec). For example, when a utility sites a generation facility or runs a load management program in its service territory that may not be the least cost option for its native load, but that frees up regional transmission constraints for others, transmission customers should compensate the utility for any additional costs incurred. A policy that guaranteed such compensation would encourage more efficient transmission and energy resource planning. (As a related matter, FERC should encourage regional transmission groups (RTGs) to include generation and demand side resource planning in their transmission-related planning efforts.)

Under the "broad" opportunity cost pricing principle described above, opportunity costs need not be limited to the variable costs of running existing plants out of order or of foregoing power sales and purchases (as ordered in NU and Penelec). If a utility sites a generating plant in its territory in order to alleviate regional transmission constraints, transmission rates should include the capital cost of that facility. Under our broader notion of opportunity cost, strategic planning can obviate constraints before they occur, and often at a price that is lower than new

transmission. A pricing policy based on this broader definition of opportunity cost would provide correct signals to utilities and other planners that the least cost solution to transmission problems may include additional generation or demand side resources, and that transmission customers will compensate utilities that rely on these "alternative" resources to the benefit of the entire grid.

Question 20. Does the failure of postage-stamp rates to recognize distance create important cross subsidies between long-distance and short-distance transfers?

Question 21. How much do transmission costs vary with distance and can such costs be easily quantified? ...

Question 23. Assess the benefits and problems of specific alternatives to the contract path approach and the need for such alternatives.

These questions will be addressed together.

Pricing approaches should provide incentives for cost-effective transmission siting and sizing decisions. These may vary substantially from region to region. In the West, while overall transmission costs may vary with distance, costs *per kilowatt* may bear little relation to the length of the transmission line over which the power is being transmitted. As noted in footnote 14 of the Discussion Paper, the Western Systems Coordinating Council (WSCC) has established a regional rating system for transmission that studies the effect of the addition of new transmission and rates the line according to the incremental transfer capability that the transmission brings. Often, stability and other considerations limit the incremental transfer capability to well below the thermal load of the line. In these cases, the cost per kilowatt over that line could be substantially more than the cost per kilowatt over a line whose transfer capability approached thermal constraints.

One approach mentioned in the Discussion Paper remarks on the WSCC's line rating methodology, and suggests that a pricing scheme based on contribution to capital based on the line rating would be feasible. The brief discussion of the WSCC system highlights the need to tailor pricing approaches to the specific features of each region's transmission, generation and demand side system. A pricing approach based on the WSCC line rating system would appear to be promising for Western utilities. FERC should ensure that such an approach is capable of reflecting synergies among generation, demand side and transmission and should establish prices that provide an incentive to capture these synergies.

*22. **Do postage-stamp or distance-sensitive rates provide adequate price signals about the location of new generators? If not, how can transmission prices help promote good location decisions?***

Any transmission prices that are based solely on the cost of either existing or new transmission will not provide adequate signals for least cost planning and siting of new generation or demand side resources. As noted in response to question 3, FERC should adopt a pricing methodology that encourages least cost solutions to an integrated generation, demand side, and transmission

grid. This necessarily includes consideration of the relative costs of generation and demand side resources that in some cases can offer a cost effective alternative to new transmission. Neither postage stamp nor distance-based rates necessarily reflect either the cost of providing additional capacity or the value of removing existing constraints or preventing future bottlenecks.

The "broad opportunity cost" approach described in response to question 6 above could be one such methodology. Others may exist as well.

Commissioners' question. What is the scope of the Commission's discretion on transmission pricing under section 212 of the FPA, and should the Commission apply the same pricing under section 205 of the FPA as it applies under section 212?

(Note: Staff did not address this question in the Discussion Paper, but it is found on page 6 of the Commission's request for comments.)

Currently, Western utilities may have transmission prices set under at least four pricing rules or policies:

1. Under section 205 of the FPA, prices for transmission have to be "fair, just and reasonable." Traditionally, this has meant embedded cost-based rates, but, as noted in the Staff Discussion Paper, in recent years deviations from that standard have been allowed.

2. Under the Western Systems Power Pool (WSPP), member utilities can negotiate short-term transmission prices anywhere up to the average cost of a hypothetical utility. The WSPP does not currently allow nonutilities to be members.

3. Section 212(a) of the FPA now has four criteria for pricing of transmission services that are ordered by FERC. They must

> (1) allow the transmitting utility to recover all the costs incurred in connection with the transmission services and necessary associated services including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities; (2) promote the economically efficient transmission and generation of electricity; (3) be just and reasonable, and not unduly discriminatory or preferential; and (4) ensure, to the extent practicable, that costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for service and not from a utility's existing wholesale, retail and transmission customers.

4. Section 9 of the Federal Columbia River Transmission System Act provides that BPA must charge generation and transmission rates that are established:

> (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles, (2) having regard to the recovery ... of the cost of producing and transmitting such electric power ...

and (3) at levels to produce such additional revenues as may be required ... to pay when due the principles of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds ...

Section 10 of that Act requires that costs of the Federal transmission system be equitably allocated between Federal and non-Federal users of the system.[8]

As we have noted throughout these comments, we believe that FERC should establish pricing policies that provide an incentive for a comprehensive regional energy delivery mechanism. Because the transmission grid is interconnected, locating a generating unit at one location in the region may have significant impacts on the entire transmission grid. Therefore, it could be detrimental to integrated planning if a potential generator could "shop around" for a location that offered the best transmission prices, unless price differences were entirely due to cost differences. We would therefore favor a FERC approach that established a uniform pricing policy for transmission regardless of whether FERC approved prices under section 205 of the FPA, section 212 of the FPA, or under the Columbia River Act.

This is not to say that the price per kilowatt of transmission should be uniform; differences in cost and other features of each utility's transmission system or individual paths may dictate different prices. However, a uniform application of pricing policies among the various transmission owners in the region would assist in sending correct price signals concerning the cost of providing transmission services to all users of the regional grid.

We believe that the three statutory provisions can be read consistently. Of the three statutes, section 212(a) is the most specific concerning the criteria FERC must apply. We agree with the principles expressed in section 212(a). Moreover, FERC has already been applying much the same principles to transmission rates approved under section 205 (in *NU* and *Penelec*). The one criterion noted in section 212(a) that FERC has not explicitly referred to in its transmission pricing orders, to our knowledge, is the second criterion, that is: "promote the economically efficient transmission and generation of electricity." While FERC orders have sought to promote economically efficient *transmission* of electricity, they have not stressed the interconnection between transmission and generation efficiency. However, the District of Columbia Circuit, in upholding FERC's order in the Western Systems Power Pool case, noted that one of the purposes of the Pool and its negotiated pricing provisions is "to reduce costs through coordination -- that is, to ensure that electricity is always generated by the least expensive means available, then moved through purchase or exchange to where it is needed." Environmental Action v. Federal Energy Regulatory Commission, ___ F.2d , slip op. at 5. FERC's approval of the WSCC was pursuant to section 205 of the FPA.

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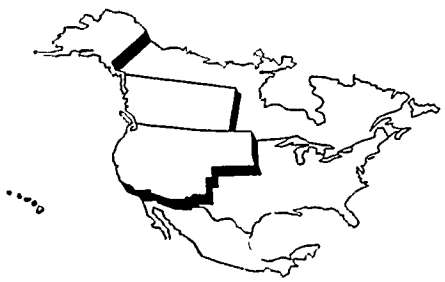
[8]Under section 212(i) of the FPA, as amended by NEPACT, FERC may also order BPA to wheel energy and capacity. Under that section, transmission rates must meet the criteria of sections 9 and 10 of the Columbia River Act but may not be "unjust, unreasonable, or unduly discriminatory." Therefore, section 212(i) may be said to add a new "hybrid" pricing standard for FERC-ordered BPA wheeling.

All of FERC's pricing policies should provide signals to coordinate transmission and generation planning and operation. Therefore, FERC in its section 205 rate approvals should apply the same criterion of promoting economically efficient transmission and generation of electricity as it will in its section 212(a) orders.

Sections 9 and 10 of the Columbia River Transmission Act likewise provides the flexibility for FERC to apply the same criteria for prices set by the Bonneville Power Administration for transmission. That Act requires that rates be set "with a view to encouraging the widest possible diversified use of electric power ..." Thus, recovery of transmission cost has never been the sole criterion for setting BPA transmission prices. Enactment of the Northwest Power Act in 1980 established BPA's role in carrying out the regional planning goals of that Act. BPA's transmission rates should contain pricing signals that contain incentives to plan and operate generation and demand side resources that are consistent with the regional energy plan. Although the process for approving BPA rates is somewhat different from rates filed by other transmission owners, FERC must ultimately approve BPA filed rates under the Columbia River Transmission Act. FERC must also review wheeling rates under section 212(i) to determine whether they are just, reasonable, and nondiscriminatory. In so doing, we urge that FERC apply the same pricing principles as it does for other Western transmission rate filings.

Reports on Western RTG Developments

This section is reserved for reports and materials from future western industry RTG meetings. The Committee on Regional Electric Power Cooperation has been invited by western electric power industry to have a representative participate in these discussions. Regular meetings are expected to continue for the foreseeable future. You will be receiving information from these meetings.



Western Interstate Energy Board/ WINB

MEMORANDUM

Alberta
Arizona
British Columbia
California
Colorado
Hawaii
Montana
Nebraska
Nevada
New Mexico
North Dakota
Oregon
Saskatchewan
Utah
Washington
Wyoming

Anita Lockwood
Chair

Douglas C. Larson
Executive Director

TO: Committee on Regional Electric Power Cooperation
State/Provincial Participants in RTG Workshop

FROM: Douglas Larson (WIEB)

DATE: November 17, 1993

SUBJECT: **Report on November 15-16 West-wide RTG Meeting**

The Committee on Regional Electric Power Cooperation has been invited to participate in each of the west-wide Regional Transmission Group (RTG) meetings. The November 15-16 meeting in Los Angeles was the first since the October 20-21 RTG workshop in Monterey. The following report is intended to keep you apprised of RTG discussions.

You may want to file this report behind Tab 2 in the *RTG Resource Book* (white binder) prepared for the Monterey workshop.

600 17th Street, Suite 1704 South Tower
Denver, Colorado 80202-5447
303/573-8910 FAX 303/573-9107

Report on November 16-17, 1993 West-wide RTG Meeting
Los Angeles, California

Jim Byrne (UT), the Committee's representative to past industry west-wide Regional Transmission Group (RTG) meetings, was unable to attend the November 15-16 meeting. State/provincial representatives in attendance were Tom Faull (ID PUC), Mary McKenzie (CA PUC), Dan Nix, Tom Flynn, Jim McClusky (CA Energy Commission) and myself. Chuck Imbrecht, Chairman of the California Energy Commission, spoke to the meeting on November 16. Steve Herod and Bud Earley from the Federal Energy Regulatory Commission also participated in the meeting.

The focus of the meeting was on the latest draft of the west-wide RTG bylaws (now called Governing Agreement). Following is a synopsis of the major topics of discussion.

A. The relationship between a west-wide RTG and subregional RTGs (e.g., which organization's rules will apply to transmission requests[1]).

- SWRTA (Southwest Regional Transmission Association) is proposing to require non-SWRTA members to abide by SWRTA rules for transmission within its region. Others object to being required to abide by rules they have not consented to.

- SWRTA believes membership in a subregional RTG should be a requisite for membership with the west-wide RTG. This idea is opposed by non-utility suppliers.

- The Northwest is working on transmission principles and the Colorado area has agreed on transmission principles for dealing with entities in their region on issues such as access and planning. Neither are planning to submit the principles to the FERC for certification. FERC is unlikely to approve a west-wide RTG if a non-certified subgroup is the body undertaking key RTG functions, such as determining access and planning.

B. Transmission planning and the relationship between the west-wide RTG and the Western Systems Coordinating Council (WSCC)

A significant gulf of opinion exists about the role (if any) of the WSCC vis-a-vis a

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[1] For example, the draft bylaws provide that if a transmission request originated and terminated in a subregional RTG, the subregional RTGs bylaws would apply. If a request originated in the part of a subregional RTG which was also part of the west-wide RTG and terminated in the west-wide RTG but outside the subregional RTG, then the west-wide RTG bylaws would apply. If the transmission request originated in that portion of the subregional RTG that is outside of the west-wide RTG and terminated in that portion of the west-wide RTG not covered by the subregional RTG, then no bylaws would apply and the applicant would go to the FERC for a Section 211 order.

There was also discussion of FERC's RTG planning requirement and whether "joint planning," as envisioned in the RTG bylaws and in WSCC activities fulfills this planning requirement. Questions were also raised about the definition of planning (e.g., does it include both reliability and economic efficiency elements?).

C. Other issues

- Impact of the tax exempt status of bonds issued for transmission construction when such transmission is for use by taxable entities.

- Granting ownership or "ownership-like" rights to transmission requestors where a transmission upgrade is necessary to honor the request and the requestor provides up-front capital for the upgrade. For new lines, ownership rights could be offered at the discretion of the utility.

- Dispute resolution.

- Preservation of rights under existing Federal Power Act provisions. There appears to be general agreement that all parties want to preserve whatever rights they currently have (e.g., the right of IOUs to file transmission tariffs under Section 205), but disagreement over the language to accomplish the objective.

- The budget for the west-wide RTG and how to allocate "administrative" and "planning" costs among RTG members.

- The degree to which existing reliability criteria used for internal company operations will be rebuttably presumed to be legitimate in any arbitration. WSCC's reliability criteria apply only to intercompany transmission, not operations within a company. Non-utility suppliers are willing to grant rebuttable presumption protection to intracompany reliability standards in effect by a date certain, but not to future changes to such criteria.

Chuck Imbrecht emphasized that: more competition in the industry is inevitable; open transmission access is the key to the new future for the industry; key elements of an RTG are broad-based membership, participation in the process by states/provinces and linkage to state/provincial planning, siting and rate regulation activities; an open transmission planning process is needed; time limits on dispute resolution are essential; RTG's are superior to state and/or federally-mandated planning; and there is a limited window of opportunity (12-18 months to reach agreement on an RTG. Thereafter, consumers and political pressures will be sufficient to demand change. Chairman Imbrecht emphasized the need for the parties to compromise.

Doug Larson reported on the **Committee's actions** (e.g., support of the WSPP, support of RTGs, support of WSCC's regional planning initiative) to foster greater short-run and long-

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~~BYLAWS GOVERNING AGREEMENT~~

WESTERN REGIONAL TRANSMISSION ASSOCIATION

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PREAMBLE

Voluntary associations, such as this Western Regional Transmission Association (Association), are intended to facilitate the efficient use of existing transmission facilities, coordinate the planning of transmission system expansions and expedite the resolution of disputes.

Pursuant to these Bylaws set forth in this Governing Agreement, Members agree to promote coordinated transmission planning, efficient use of transmission capacity, nondiscriminatory access to transmission facilities and fair pricing for transmission services.

1. PURPOSE.

The Association is a voluntary organization of Transmission Providers, Transmission Users and Commissions located throughout the Western Interconnection. Members have formed the Association to foster the efficient, equitable and reliable use of existing and future transmission facilities and the expeditious and fair resolution of disputes related to transmission access. The Association shall, to the extent practicable in cooperation with the WSCC, provide a forum for coordination of transmission planning and for the exchange of information to assist Members in meeting their transmission needs. To the extent practicable, the Association shall pursue the activities contemplated hereunder in a manner that avoids duplicating the activities of other transmission planning

organizations such as the WSCC and Subregional Coordination Groups.

2. DEFINITIONS.

When capitalized herein, whether in singular or plural, the following terms shall have the following meaning:

2.1 Arbitrator. An individual selected to resolve disputes arising under these Bylaws pursuant to Section 12.

2.2 Arbitration Committee. The Committee described in Subsection 6.7.

2.3 Available Transmission Capacity. That amount of transmission capacity available to a Transmission Provider to provide transmission service to a Transmission User which is not reasonably required to accommodate the Transmission ~~User's~~ Provider's: (i) Native Load; (ii) existing commitments for firm wholesale sales contracts; (iii) existing contractual and statutory commitments for firm transmission service; ~~and~~ (iv) Prudent Reserve and (v) limitations on use of transmission facilities imposed by statutes or regulations.

2.4 Award. A decision of an Arbitrator made pursuant to Subsection 12.3 of these Bylaws.

2.5 Board. The Association's Board of Directors, as described in Section 5.

2.6 Commissions. State or provincial utility regulatory commissions or energy commissions.

2.7 Committee. A Committee of Members established pursuant to these Bylaws or by the Board.

2.8 Existing Facilities. Those transmission facilities owned by a Member or transmission capacity under contract to a Member ~~that have been~~ previously used to transmit electric energy.

2.9 FERC. The Federal Energy Regulatory Commission or a successor agency.

2.10 FPA. The Federal Power Act as it may be amended from time to time.

2.11 Incremental Facilities. Transmission facilities, other than Existing Facilities, that are reasonably required to be used to satisfy a request for transmission service from a Transmission User.

2.12 Interconnected Transmission System. That portion of each Transmission Provider's transmission system utilized for bulk power transactions, generally at voltages of 115 kV and higher.

2.13 Member. Any signatory to ~~these Bylaws~~ this Governing Agreement which is a Transmission Provider, a Transmission User or a Commission operating or located in the Western Interconnection.

2.14 Native Load. Load associated with retail customers and full or partial requirements wholesale customers for which a Transmission Provider, by statute, franchise, contract or ~~FERC~~ federal, state or provincial policy or regulation, has undertaken the obligation to plan, construct and operate its system to provide reliable service.

2.15 Planning Committee. The Committee described in Subsection 9.1.

2.16 Power Marketing Agency. The Western Area Power Administration or the Bonneville Power Administration.

2.17 Prudent Reserve. An amount of transmission capacity set aside for a Transmission Provider's reasonable reliability requirements as determined by the reliability criteria of such Member and consistent with Prudent Utility Practice and regional reliability council criteria, which requirements shall be impartially applied without undue discrimination.

2.18 Prudent Utility Practice. Those practices, methods and acts, including levels of reserves and provisions for contingencies, as may be modified from time to time, that are commonly used in the Western Interconnection to: (i) operate electric systems dependably, reliably, safely, efficiently, economically and in accordance with all applicable laws and governmental rules, regulations and orders; (ii) serve customers; and (iii) prevent material adverse effects on neighboring electric systems.

2.19 Subregional Coordination Groups. Voluntary subregional associations involving Members that may be organized from time to time to exchange information and coordinate local transmission planning in subregions of the Western Interconnection whose ~~policies and activities are not inconsistent with these Bylaws~~ governing documents have been ~~approved by the FERC~~.

2.20 Transmission Provider. Any Member owning or having contractual rights to use transmission facilities located in the Western Interconnection.

2.21 Transmission User. Any Member entitled to apply to the FERC for an order requiring transmission services pursuant to Section 211 of the FPA or any Member that is located outside the United States that would be entitled to apply for such an order were it located within the United States.

2.22 Western Interconnection. The area comprised of those states and provinces in Western Canada, Northern Mexico and the Western United States in which ~~Transmitting Utilities,~~ Transmission Providers, which are members of the WSCC, operate synchronously-connected transmission systems.

2.23 WSCC. The Western Systems Coordinating Council.

3. MEMBERSHIP.

3.1 Qualifications. Any entity meeting the definition of a "Member," set forth in Subsection 2.13, shall be admitted to membership in the Association upon executing ~~these Bylaws~~ this Governing Agreement and providing notice of its having done so to the Board and FERC.

3.2 Classifications of Members. Upon being admitted for membership, each Member shall designate which one of the following classifications of Members to which it wishes to be assigned:

a. Major Transmitting Utility

b. Transmission-Dependent Utility

c. Nonutility Supplier

d. Commission

3.3 Membership Responsibilities. Each Member, other than a Commission, shall:

3.3.1 Conduct or participate in joint studies which affect such Member's system; provided, however, no Member shall be required to participate in a study exclusively related to its own system that is initiated by another party unless such study is necessary to respond to a request for transmission service under these Bylaws.

3.3.2 Provide necessary information, data and plans as specified by the Planning Committee to assure coordinated planning of transmission projects.

3.3.3 Provide full and timely responses to requests for transmission service as specified in Section 10.

3.3.4 In regard to transmission service requests at 69 kV or lower voltages, or for other facilities for which the Association does not collect data, provide to the Transmission User, or other Members, system data necessary to conduct system studies, if so desired by the Transmission User or other Members.

3.3.5 Pay its share of administrative and planning costs as described in Section 8 below.

3.3.6 Make its employees available for reasonable periods at no cost to serve as facilitators or Arbitrators of

disputes among Members arising out of the application of these Bylaws.

3.3.7 Make transmission services available to other Members consistent with the provisions of Subsection 10.1.

3.4 Withdrawal from Membership. Any Member may withdraw from the Association upon providing written notice of its withdrawal to the Board and the FERC. Notwithstanding such notice of withdrawal, all Awards and requests for transmission service to be provided by such Member in effect or pending as of the date of the receipt of written notice of withdrawal shall be followed to completion, pursuant to these Bylaws by the withdrawing Member; provided, however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of these Bylaws. Any Member which has voluntarily withdrawn from the Association may not reapply for Membership for a period of one year from the date of its withdrawal.

3.5 Termination of Membership. At any time that a Member becomes delinquent in the payment of any administrative and operating costs which are incurred during its membership and fails after 90 days of receipt of a written notice to pay such costs, or if the Board finds that a Member has: (i) intentionally or repeatedly violated any Bylaw of the Association, (ii) breached or violated any Award issued pursuant to its membership in the Association, or (iii) willfully obstructed any lawful purpose or activity of the Association, the Board,

in its sole discretion, may terminate the Member's membership. The affected Member shall be afforded at least 21 days advance written notice of any Board meeting at which termination of the Member will be considered and such Member shall have the right to be present and present information to the Board concerning any proposed termination action. Upon termination of membership, all of the Member's voting rights and other rights of membership shall cease. Notwithstanding such notice of termination, all Awards and requests for ~~Firm T~~transmission ~~S~~service to be provided by such Member in effect or pending as of the effective date of termination shall be honored by the terminated Member; provided, however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of these Bylaws. A Member which has been terminated from membership may not reapply for membership for a period of time stated in the Board resolution of termination, which shall not exceed a period of five years.

4. MEETINGS OF MEMBERS.

4.1 Annual Meeting. A meeting of the Members shall be held within 60 days of the effective date of ~~these Bylaws~~ this Governing Agreement and thereafter at least annually, within the Western Interconnection on a date and at a time and place fixed by the Board.

4.2 Notice of Meeting. Written notice of every meeting of the Members shall be prepared and mailed to the last known address of each Member not less than 21 nor more than 60 days

before such meeting. Such notice shall state the time and place of the meeting and the meeting agenda.

4.3 Voting. Each Member, other than a Commission, shall be entitled to one vote upon each matter submitted to a vote at a meeting of the Members. Except in regard to the election of Directors, all matters coming before the full Membership shall require the affirmative vote of two-thirds of the Members of each voting Membership classification present at the meeting in order to be adopted.

4.4 Quorum. A majority of the total number of Members with voting rights shall constitute a quorum necessary for the transaction of business at any annual or special meeting of the Members. Those Members present may adjourn from time to time until a quorum is present with no further notice of the meeting required.

5. GOVERNANCE.

5.1 Board of Directors. The Association shall have a Board of Directors comprised of 21 Directors. Directors shall be selected from among the three classifications of voting Members and each such classification shall be entitled to ~~vote upon~~ elect and be represented by the following number of Directors:

a.	Major Transmitting Utilities	7
b.	Transmission-Dependent Utilities	7
c.	Nonutility Suppliers	7

5.2 Ex-Officio Directors. Commission Members ~~shall~~ may select up to three Directors to serve in an ex-officio status on the Board. Such ex-officio directors shall be invited to attend and participate in all meetings of the Board, and Committees, but shall not have a right to vote on matters coming before the Board or Committees.

5.3 Diversity of Directors. Each Director in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have his or her principal place of business in a different state or province, provided, however, two directors in ~~any~~ each of these two classifications may be from California. No more than one Director ~~in any classification~~ may be employed by or be affiliated with any Member. At least three of the Directors in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have their principal place of business in the states of Texas, Arizona, New Mexico, California, Nevada or the states of Mexico and at least three of the Directors in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have their principal place of business in the states of Oregon, Washington, Idaho, Montana, Utah, Wyoming, Colorado or the provinces of British Columbia or Alberta.

5.4 Election of Directors. At each annual meeting of the Members, elections shall be held to fill any vacancies on the Board. Directors shall be selected from within each classifi-

cation for each position by a plurality vote of the Members of that classification. No person may be nominated for a Director position if his or her election would violate the provisions of subparagraph 5.3. Except as applied to the initial Board, Directors shall be elected for terms of three years and until a successor is elected and qualified. The initial Board shall determine the length of each Director's term by drawing lots, with ~~seven~~ three Directors in each classification serving terms of three years, ~~seven~~ two Directors in each classification serving terms of two years, and ~~seven~~ two Directors in each classification serving terms of one year.

5.5 Removal of Directors and Vacancies. An individual Director may be removed from office by and at the discretion of a Member employing the Director or by majority vote of the classification of Members represented by the Director to be removed. Whenever a vacancy occurs, ~~other than from expiration of a term of office,~~ a Director's remaining term shall be filled by majority vote of the remaining Directors representing the class of Members whose Director's position became vacant until the next annual meeting at which time it shall be filled by a plurality vote of the classification represented by such Director.

5.6 Annual Board Organizational Meeting. A meeting of the Board shall be held at the conclusion of each annual meeting of the Members for the purpose of electing the officers

of the Association for the upcoming year and to transact such other business as may come before the meeting.

5.7 Regular Meetings. Regular meetings of the Board, in addition to its annual meeting, shall be held upon such notice and at such time and place as the Board may determine. The Board may hold meetings by conference call.

5.8 Special Meetings. A special meeting of the Board shall be held whenever called by the President or, during the President's absence or disability, by the Vice President, on notice delivered by first class mail or facsimile at least seven days prior to the meeting. Special meetings shall be called by the President or Secretary in like manner and on like notice on the written request of any four Directors.

5.9 Quorum and Voting. Two-thirds of the Directors in each voting membership classification shall constitute a quorum necessary to the transaction of business at any meeting of the Board. All matters coming before the Board shall require the affirmative vote of two-thirds of each voting class of Directors. By providing ~~advance~~ written notice to ~~all other Directors, the President,~~ a Director may designate an alternate to attend any Board meeting and such alternate shall have full authority to act and vote in place of the absent Director.

5.10 Action Without a Meeting. Any action which may be taken at a meeting of the Board, or of a Committee, may be taken without a meeting if set forth and approved by a writing signed by all Directors or Committee members, and such action

shall be effective on the date on which the last signature is placed on such writing, or such earlier effective date as is set forth therein.

6. DUTIES OF DIRECTORS.

6.1 General Powers. The Board shall manage the business and affairs of the Association, and shall exercise all of the powers of the Association except such as are by law or these Bylaws conferred upon or reserved to the Members. The Board shall recommend any amendments to the Bylaws for approval by the Members and may adopt such policies, rules, regulations, and actions which are consistent with law and these Bylaws as it may deem advisable.

6.2 Selection of Manager and Agents. The Board shall select and employ a Manager and fix the compensation of such Manager. The Board may terminate the employment of the Manager with or without cause at any time. The Board shall also have authority to authorize the employment of other staff members or retain agents to provide defined activities and services.

6.3 Budgets. The Board shall periodically establish and approve a budget which includes all costs of administration for the Association as well as any anticipated planning costs to be allocated to the Members. Such budgets shall be established and approved not less than annually.

6.4 Accounting System and Audit. The Board shall install and maintain an adequate system of accounts and records. At least annually, the books and accounts of the Association shall

be audited by a certified public accountant and the report of such audit shall be made at the next annual meeting of the Members.

6.5 Committees. The Board shall ~~appoint or create and, except for the Planning and Arbitration Committees,~~ terminate Committees as it deems appropriate. Membership on all Committees appointed by the Board shall be allocated among membership classifications and geographic regions on generally the same proportional basis as required for Board membership. The organizational form and term of Committee chairpersons and other positions shall be established by the Board. ~~In regard to each Committee, the Board shall appoint a cochairperson from each of the three membership classifications. The three cochairpersons shall alternate responsibility for chairing the committee as among themselves so that cochairpersons representing any membership classification shall not have such responsibility for more than ten months during any 24-month period. Cochairpersons shall serve terms of three years unless a shorter term is established by the Board.~~ Reasonable advance notice of all Committee meetings shall be given to all Members. Attendance at all Committee meetings shall be open to any Member ~~and all members in attendance at such meetings shall be deemed members of the Committee, provided that only Committee members from membership classifications with voting rights shall have the right to vote on matters coming before the Committee,~~. Matters coming before Committees shall be ~~resolved~~

adopted only by a majority vote of Committee members ~~voting~~ present in each membership classification with voting rights.

6.6 Planning Committee. The Board shall appoint a Planning Committee whose function is described in Section 9.1. ~~The Membership of the Planning Committee shall include the Chairpersons of all Subregional Coordination Groups.~~ Three ~~members of the Planning Committee,~~ persons representing the Transmission-Dependent Utility, Nonutility Supplier and Commission classifications, respectively, shall be designated by the Planning Committee to serve as liaisons with the planning committees of the WSCC and ~~to otherwise represent the interests of members who are not WSCC members~~ other planning bodies.

6.7 Arbitration Committee. The Board shall appoint an Arbitration Committee consisting of one representative of each of the three voting Membership classifications. The Arbitration Committee shall have the responsibilities described in Subsection 6.9 and Part 12.2.~~1~~2 and shall also, from time to time, review the arbitration procedures set forth in these Bylaws and consider proposed changes to be presented to the Board. Members of the Arbitration Committee shall disqualify themselves from participating in any dispute involving such member's employer.

6.8 Other Committees. The Board may authorize such additional committees as it deems necessary to carry out the business of the Association. The Board shall set forth the

duties and responsibilities of each such Committee in writing at the time of the creation of the Committee. Each such Committee shall be subject at all times to control and direction of the Board. Copies of the minutes of each ~~such~~ Committee meeting, including Planning and Arbitration Committee meetings, shall be mailed to all Directors.

6.9 Qualified Arbitrators. The Board shall establish and from time to time update a list of qualified Arbitrators ~~who are employed by Mmebers and facilitators~~. The list of Arbitrators and facilitators may be subdivided by the Arbitration Committee into specific types of disputes that an Arbitrator or facilitator is considered to be qualified to decide or by subregional areas concerning which an Arbitrator or facilitator has expertise. All arbitrator names supplied by the Arbitration Committee pursuant to Part 12.2.1 shall be taken at random from the Board-approved list or, at the election of all disputing Members involved in a dispute, subdivisions of that list.

~~6.10 Subregional Coordination Groups. The Board shall review bylaws of proposed Subregional Coordination Groups and determine whether the bylaws, policies and activities of such groups are consistent with these Bylaws. Upon an affirmative determination by the Board in regard to such bylaws, the Subregional Coordination Group shall be recognized as such by the Association and afforded the benefits of Subsections 6.6, 9.1 and 9.1.6.~~

7. OFFICERS AND MANAGER.

7.1 Election of Officers. At each annual meeting of the Board of Directors, the Board shall elect a President, a Vice President, a Secretary and a Treasurer. The President and Vice President shall be ~~chosen from the~~ Directors of the Association. An officer may be removed by the Board whenever in its judgment the best interests of the Association will be served thereby. If any vacancy shall occur among the officers of the Association, it shall be filled by the Board of Directors at its next regular meeting following the vacancy.

7.2 Duties of President. The President shall: (i) preside over all meetings of the Association and the Board; (ii) call special meetings of the Board; and (iii) perform all duties that may be reasonably required ~~of him~~ by the Association or the Board.

7.3 Duties of Vice President. In the absence or disability of the President, the Vice President shall perform the duties of the President.

7.4 Duties of Secretary. The Secretary shall attend all meetings of the Board and all meetings of the Members and record all votes and keep a complete record of all meetings of the Association and of the Board and shall have general charge and supervision of the books and records of the Association. The Secretary shall sign all papers pertaining to the Association as may be authorized or directed by the Board. The Secretary shall serve all notices required by law and by these

Bylaws including notices of meetings and shall make a full report of all matters and business pertaining to the office to the Members at the annual meeting. The Secretary shall make all reports required by law and shall perform such other duties as may be requested by the Board.

7.5 Duties of Treasurer. The Treasurer shall perform such duties with respect to the finances of the Association as may be prescribed by the Board.

7.6 Duties of Manager. The Manager shall perform such duties and shall exercise such authority as the Board may from time to time vest. The Manager shall put in place and maintain Association newsletters and/or an electronic bulletin board sufficient to keep Members timely informed of events related to Members' activities carrying out the purposes of these Bylaws.

7.7 Compensation. The salary, compensation and other benefits of the Manager and any other staff shall be fixed by the Board. No member of the Board shall receive any compensation or other benefits.

8. MEMBER COSTS.

8.1 Administrative Costs. The administrative costs of the Association shall be allocated ~~as follows:~~

~~8.1.1 25% of the total costs shall be allocated among the Members, other than Commissions, on a per capita basis, and~~

~~8.1.2 75% of the total costs shall be allocated among the members based upon total revenues from the sale of~~

~~electricity.~~ among Members on a basis determined by the Board in advance of each year for which such costs are to be paid.

8.2 Planning Costs. The costs of planning studies or other activities not undertaken in response to a request for transmission services, if undertaken by the Association, shall be generally allocated among the Members benefitting from such activities in proportion to the amounts of transmission capacity in megawatts desired by each participating Member. Specific activities and cost allocations may be memorialized in separate agreements among the participating Members.

9. COORDINATED PLANNING AND ACCESS.

9.1 Planning Committee Functions. The Board shall appoint a Planning Committee. The Planning Committee shall provide a forum for coordination of transmission planning activities within the Association by facilitating the prompt exchange of information among Members through use of a common data base in order to: (i) assist timely responses by Members to requests for transmission service, (ii) assist the development of coordinated transmission plans to serve the needs of all Members, and (iii) support the Association's interface with WSCC, other industry organizations, regulatory bodies and Subregional Coordination Groups. To carry out these responsibilities, the Planning Committee, in conjunction with the WSCC to the extent practicable, shall:

9.1.1 Provide a forum for coordinating transmission plans, sharing system data, facilitating the joint development

of new transmission projects, and meeting the transmission facility planning needs of Members.

9.1.2 Collect, or cause to be made available, Member information, data and transmission plans as determined by the Planning Committee in order for the Association to meet its objectives.

9.1.3 Collect and make available to all Members the internal planning criteria of individual Members.

9.1.4 Ensure that ~~new project~~ transmission studies and information regarding new transmission facilities are available to all Members who request it.

9.1.5 Prepare, when appropriate, Association planning information reports and maps for government regulatory agencies, reliability councils and others, as requested, including coordinating Transmission Providers' reports to the FERC required by rules promulgated pursuant to Section 213(b) of the FPA.

9.1.6 Refer to Subregional Coordination Groups matters having principally subregional interest.

9.1.7 Periodically review and make recommendations to the Board concerning the procedures for obtaining transmission services provided for in these Bylaws.

9.1.8 Carry out other activities as directed by the Board.

9.2 Planning Information. Each Transmission Provider shall file on an annual basis with the Planning Committee

information regarding its existing and planned Interconnected Transmission System. If Members are also members of a Subregional Coordination Group which assembles planning information, the Planning Committee shall coordinate its data collection activities with the Subregional Coordination Group so as to avoid duplication of effort, to the extent practicable. The Planning Committee shall determine what data are required, including the years for which the data are to be reported and the format of the data, to assure that the objectives of the Association are met. The data submitted by each Transmission Provider for its Interconnected Transmission System shall be in a consistent format, to the extent feasible, with the format established by the WSCC and shall include, at a minimum, data necessary to comply with Section 213(b) of the FPA and rules and regulations promulgated thereunder. All Members shall be able to obtain, through the Association, information necessary for the determination of available transmission capacity on transmission systems of other Members.

9.3 Planning Coordination.

9.3.1 No member shall be required to implement a planning recommendation made by the Planning Committee or the Board; provided, however, no member shall be relieved of its obligation to respond to requests for transmission services as required by these Bylaws or to implement the provisions of an Award.

9.3.2 Members involved in the development of transmission projects that may interconnect two or more utility systems shall provide notice of opportunity to participate in development study work to all Members by posting in the Association's newsletter or electronic bulletin board. Members shall respond in writing to the sponsoring Members within 60 days after notice is posted indicating whether they elect to participate in such studies. Those Members participating in joint project studies shall periodically share the results of the study work with the Planning Committee.

9.3.3 Costs for joint planning studies shall be shared on an equitable basis among those Members participating in the studies. Study costs may include computer costs, staff time, report preparation, report distribution and appropriate overhead costs, as applicable, but shall not include profits for the Member conducting the study.

9.3.4 Arrangements among participating Members for joint studies shall be documented by letter agreement or other appropriate instrument prior to the beginning of the studies.

9.4 ~~Interface with WSCC~~Coordination. In order to avoid unnecessary duplication, ~~Transmitting Utilities~~ Transmission Providers shall utilize WSCC reports and data to the maximum extent practicable to fulfill the information reporting requirements set forth in Subsection 9.2. The Planning Committee shall develop standard forms, ~~if not already available,~~ which ~~Transmitting Utilities~~ Transmission Providers

can use to fulfill reporting requirements for the WSCC, the Association, Subregional Coordination Groups and the FERC. All data collected directly by the Association, or in cooperation with the WSCC, shall be reasonably available to all Members through the Association regardless of its physical location.

9.5 Planning Criteria.

9.5.1 The applicable reliability criteria, standards, guidelines and operating procedures of the North American Electric Reliability Council, the WSCC, other electric reliability councils, and of the individual Transmission Provider shall govern the design and operation of each such Member's transmission system; provided, however, ~~i~~individual ~~Transmitting Utilities'~~ Transmission Providers' reliability criteria, standards, guidelines and operating procedures shall be reasonable and consistent with Prudent Utility Practice and shall be consistently applied in determining available transmission capacity or determining what system additions are required.

10. REQUESTS FOR TRANSMISSION SERVICE.

10.1 Service to be Provided. Subject to the provisions of Section 14, each Transmission Provider shall provide transmission service from its Available Transmission Capacity on its Existing Facilities, or from Incremental Facilities where necessary, to any Transmission User on a basis consistent with the FPA, ~~and with~~ FERC's ~~then-applicable~~ standards and policies and this Governing Agreement and as detailed in the

Transmission Provider's applicable tariff, or an agreement negotiated between such Members or established ~~through Arbitration, by an Arbitrator,~~ if such tariff does not exist. Canadian or Mexican Transmission Providers ~~may establish prices~~ shall provide service based upon policies ~~different than, but~~ and pricing methodologies no less favorable to Transmission ~~u~~Users~~,~~ than those established by the FERC. Members not subject to Section 211 of the Federal Power Act ~~nonetheless~~ agree to provide transmission service on the same basis as those ~~that are~~ Members that are subject to such requirements.

10.2 Tariff or Agreement Required. Transmission service shall be provided solely under a separate tariff or agreement and these Bylaws shall not, in and of themselves, be construed to be a tariff or service agreement providing for transmission service.

10.3 Request for Service. Each Transmission User desirous of transmission services ~~from a Transmission Provider~~ shall, in each instance, pursue its request for such service pursuant to these Bylaws in lieu of exercising its procedural rights pursuant to Section 211 of the FPA. A Transmission User requesting transmission service shall provide to the Transmission Provider information regarding its request for transmission service, consistent with either the FERC's then current policy regarding such request (as currently embodied in its "Policy Statement Regarding Good Faith Requests for

Transmission Services") or the tariff of the Transmission Provider under which transmission service is sought.

10.4 Response to Request for Firm Transmission Service.

10.4.1 The Transmission Provider shall respond to a request for transmission service from a Transmission User in a manner consistent with Section 212 of the FPA and FERC's then current policies (as presently embodied in its "Policy Statement Regarding Good Faith Requests for Transmission Services").

10.4.2 The Transmission Provider may elect to provide the requested transmission service, or to conduct a study, including any required environmental studies, if such is reasonably required, at the Transmission User's expense, to determine: (i) whether it has sufficient Available Transmission Capacity to provide the requested service initially and for the full term of the request and (ii) what upgrades, additional transmission facilities or interconnections are required to accommodate the requested service. The Transmission Provider's reasonable study costs shall be billed to and paid by the Transmission User in advance based upon the Transmission User's reasonable estimate of such costs. Any reconciliation for over or underpayment shall be done upon completion of the study work. Such study shall be completed within a reasonable time period in accordance with the FERC's then-current policies, as agreed to by the Transmission Provider and Transmission User or, if such Members cannot agree, as determined by the Planning Committee. The Transmission Provider shall be responsible for

conducting the study with participation and input from the Transmission User, as mutually agreed to, and the results of the study shall be made available to the Transmission User, the Coordination Committee, and any other Member requesting it.

10.5 Requests Requiring Upgrades, Additional Facilities or Interconnections.

10.5.1 If the Transmission Provider's report issued at the completion of a study performed pursuant to Subsection 10.4 concludes that the Transmission Provider does not have sufficient Available Transmission Capacity to provide the requested service initially or for the term of the request, it shall include at a minimum: (i) the estimated cost of and cash flow requirements for installing the necessary facilities or providing the interconnection; (ii) the estimated time necessary to build such facilities or provide such interconnection, including the estimated time required for environmental studies, licensing and regulatory approvals, ~~and~~ (iii) the estimated incremental capacity added to the transmission system by the additional facilities, (iv) whether the Transmission User will be expected to contribute capital in connection with installing the necessary facilities or providing the interconnection, (v) whether the Transmission User will have the option of contributing capital in connection with installing the necessary facilities or providing the interconnection, and (vi) a description of the rights the Transmission User shall enjoy if it contributes capital to the project.

10.5.2 If the study results demonstrate a need for a transmission interconnection with another entity, the Transmission Provider shall make a good faith effort to arrange a joint study with the other entity to evaluate the impact of such an interconnection. Costs for this additional study shall also be borne by the Transmission User.

10.5.3 If the study results demonstrate a need for and the feasibility of building new facilities or providing an interconnection, the Transmission User may elect to have the required facilities constructed by the Transmission Provider. The Transmission Provider shall be obligated to build the project based upon the conditions outlined in the Transmission Provider's report and an agreement negotiated between the Transmission Provider and the Transmission User, subject only to state and provincial law, the FPA and FERC's standards and policies. The Transmission Provider shall provide notice of the project to all Members through posting in the Association newsletter or electronic bulletin board.

10.6 Requests Involving Only Members of Subregional Coordination Groups.

If a request for transmission service involves only Members who are also members of a Subregional Coordination Group and the governing documents of such Subregional Coordination Group provide for a process for requesting transmission service, the process of the Subregional Coordination Group, as opposed to that set forth in this Section 10, shall be

followed. To the extent the governing documents of the Subregional Coordination Group establish different principles regarding the provision of transmission service, or the pricing thereof, than those of the Association, the principles of the Subregional Coordination Group shall govern as among members of the Subregional Coordination Group.

11. PRICING.

Pricing of transmission service by a Transmission Provider in response to any request for transmission service shall utilize pricing procedures and methodologies for use of Existing Facilities and Incremental Facilities (if applicable) in a manner consistent with the FPA and ~~the then established~~ then applicable standards and policies of the FERC or as provided for in existing FERC-approved tariffs, where extant. ~~Transmitting Utilities~~ Transmission Providers in Canada or Mexico may rely upon pricing policies of regulatory bodies other than the FERC if such policies are no less favorable to Transmission Users than those of the FERC. Notwithstanding the foregoing, any Transmission Provider may, from time to time, request through a petition for declaratory ruling, or request for rulemaking, that the FERC find a particular form of transmission pricing just and reasonable; provided, however, pending the resolution of such petition or request, established policies shall govern.

12. DISPUTE RESOLUTION.

12.1 Preconditions to Arbitration.

12.1.1 Members shall make best efforts to settle all disputes associated with transmission access or services, including but not limited to, disputes concerning amounts and location of Available Transmission Capacity, as well as costs, prices, and terms and conditions of transmission service. In the event any such dispute is not settled, any disputing Member may request in writing that the Manager appoint an impartial facilitator from the Association membership to aid the disputing Members in reaching a mutually-acceptable resolution to the dispute and such appointment shall be made within ten days. The facilitator and representatives of disputing Members with authority to settle the dispute shall meet within 21 days after the facilitator has been appointed to attempt to negotiate a resolution of the dispute. A resolution may ~~consist of~~ include referring the matter to ~~another~~ a technical body (such as a WSCC Technical Advisory Panel) for resolution or an advisory opinion.

12.1.2 If the disputing Members have not succeeded in negotiating a resolution of the dispute within 30 days after first meeting with the facilitator pursuant to Paragraph 12.1.1, such Members shall be deemed to be at impasse and either Member may commence the ~~binding~~ arbitration process.

12.1.3 Disputes related to the interpretation or performance of treaties or executed agreements or service

schedules that have been approved or accepted for filing by the FERC shall not be subject to Arbitration under these Bylaws unless otherwise agreed by the disputing Members. Disputes only involving Members who are also members of a Subregional Coordination Group whose governing documents provide for a dispute resolution mechanism shall be resolved in accordance with such dispute resolution mechanism.

12.2 Arbitration Process.

12.2.1 Within 14 days of ~~the~~ a disputing Members' ~~reaching impasse, request that the arbitration process be commenced,~~ each disputing Member shall submit a statement in writing to the other disputing Members, which statement shall set forth in reasonable detail the nature of the dispute, the issues to be arbitrated, and the proposed Award sought through such arbitration proceedings. To the extent disputing Members do not agree on a form of a required contract for transmission service, each submittal shall include proposed contract language for those issues in dispute. These statements shall constitute the sole submittal of statements for arbitration. A summary of such statement of issues shall be published in the Association's newsletter or electronic bulletin board.

12.2.2 Within ten days following the submission of their statements, the disputing Members~~,~~ shall select an Arbitrator. The arbitration shall be conducted by ~~a~~ an Arbitrator familiar with and knowledgeable about the policies and criteria used in the Western Interconnection, transmission

systems, and regulatory requirements. If the disputing Members cannot agree upon an Arbitrator, ~~each the~~ disputing Members shall take turns striking names from a list of ten qualified individuals supplied by the Arbitration Committee from the list maintained by the Board pursuant to Subsection ~~3~~6.9 with a disputing Member chosen by lot first striking a name. The last-remaining name not stricken shall be designated as the Arbitrator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected who is able and willing to serve. No person shall be eligible for selection as an Arbitrator who is a past or present officer, member of the governing body, employee or consultant of any of the disputing Members, or of an entity related to or affiliated with any of the disputing Members or is otherwise interested in the matter to be arbitrated. Any individual designated as an Arbitrator shall make known to the disputing Members any such disqualifying relationship and a new Arbitrator shall be designated in accordance with the provisions of this subparagraph.

12.2.3 The Arbitrator shall determine what arbitration procedures shall apply, consistent with these Bylaws, taking into account the complexity of the issues involved, the extent to which factual matters are disputed and the extent to which the credibility of witnesses is relevant to a resolution. The Arbitrator shall consider all issues underlying a dispute

including, if relevant, the reasonableness of a disputing ~~Transmitting Utility Member's~~ Transmission Provider's reliability criteria; provided, that reliability criteria which are based upon regional reliability council criteria in effect as of January 1, 1994 shall be afforded a rebuttable presumption of reasonableness and consistency with Prudent Utility Practice by the Arbitrator. The Arbitrator may elect to resolve the disputed matter solely on the basis of written submittals.

12.2.4 The Arbitrator shall take evidence submitted by the disputing Members in accordance with procedures established by the Arbitrator and may request additional information including the opinion of recognized technical experts. Such additional information shall be furnished by the disputing Member or other Members having such information. Disputing Members shall be afforded a reasonable opportunity to rebut any such additional information. Other ~~interested Members~~ affected parties may request in writing that the Arbitrator consider additional information and the Arbitrator may consider such additional information, subject to a right of the disputing Members to have a reasonable opportunity to rebut such additional information.

12.3 Award. Within 115 days of his or her selection as Arbitrator, the Arbitrator shall select, by written notice to the disputing Members, the proposed Award of a disputing Member which best meets the terms and intent of these Bylaws and

conforms with the FPA and FERC's standards and policies; provided, however, if the Arbitrator concludes that neither proposed Award is consistent with law or applicable FERC policy, the Arbitrator shall specify how each proposed Award is deficient and request that the Disputing Members submit new proposed Awards that cure the deficiency perceived by the Arbitrator. A written decision explaining the basis for the Award shall be provided by the Arbitrator with the written notice to parties. Both notice and decision shall be published in the Association's newsletter or electronic bulletin board. No Award shall be deemed to be precedent that is binding on an Arbitrator in any other arbitration related to a different dispute.

12.4 Compliance and Costs. Immediately upon the decision by the Arbitrator, except as provided for in Subsection 12.5, the disputing Members shall take whatever action is required to comply with the selected Award to the extent the selected Award does not require regulatory action and shall pursue no avenue of appeal~~, except as provided for in Subsection 12.5~~. To the extent the Award requires state or provincial regulatory action, FERC review of an Award involving a Power Marketing Agency or a FERC filing by a Transmission Provider subject to FPA Sections 205 or 206, the affected Member shall submit and support that portion of the Award with the appropriate regulatory authority. Any and all costs associated with the arbitration shall be borne by the Member or Members whose

proposed Award was not selected, unless the disputing Members agree to an alternate method of allocating costs.

12.5 FERC Appeal. A disputing Member may apply to the FERC to hear an appeal of any Award only upon the grounds that the Award is contrary to or beyond the scope of these Bylaws or is unjust, unreasonable, unduly discriminatory or preferential or otherwise inconsistent with the FPA or FERC's standards or policies. ~~The Members hereby agree that in the event of an application to hear an appeal of an Award, the FERC may elect to not hear such an appeal. No Member shall seek judicial review of a FERC order declining to hear an appeal and no FERC decision not to hear an appeal shall be construed as reflecting a FERC decision on the merits or be otherwise considered precedential. If the FERC fails to act on an application for an appeal within 90 days, it shall be deemed to have agreed to hear the appeal.~~ Any ~~such~~ appeal to the FERC shall be based solely upon the record assembled by the Arbitrator, ~~but no~~ and deference shall only be afforded to the ~~conclusions or judgments~~ factual findings of the Arbitrator. The Parties expect that FERC will consider an appeal on the same basis that it reviews initial decisions of Administrative Law Judges pursuant to 5 USC § 557. ~~Appeals to FERC filed on behalf of entities not otherwise subject to the jurisdiction of the FERC shall be deemed to involve an application for an order requiring transmission service pursuant to Section 211 of the FPA and shall be filed by the Transmission User on behalf of~~

~~the appealing Member regardless of whether the Transmission User is the appealing Member involved in the dispute. If the FERC undertakes to hear a Member's appeal, judicial review of the FERC's resulting order may be sought from a court of competent jurisdiction.~~

12.6 Procedure for Appeals. ~~Any disputing Member wishing to appeal an Award~~ Following any Award, the Member requesting transmission service before the Arbitrator shall ~~cause~~ file a fully-documented application ~~to be filed~~ with the FERC, pursuant to Section 211 of the FPA, within 14 days of the entry of the Award, including a copy of the Award and the Arbitrator's decision. Such filing may also include an appeal of the Award by the requesting Member, in which case the application shall set forth the basis for the appeal as well as all supporting facts and authority. Any other party to the dispute may appeal the Award, or respond to an appeal by the requesting Member, by filing a response within 14 days of the filing of the application. Such response shall set forth the basis for any appeal or defense of the Award and all supporting facts and authority for such appeal or defense. The Member filing the application may file a defense of the Award in response to any appeal within 14 days of the filing of such appeal. Any appeal of any Award and any defense of an Award shall include a statement indicating whether the FERC should stay the implementation of the Award and what conditions should be attached to any such stay, together with supporting arguments.

The Member appealing an Award shall cause the entire record of the arbitration to be filed with the FERC, with a copy to all other disputing Members within 14 days of initiating the appeal. If no appeal of the Award is made in the application or any response thereto, the FERC shall grant the application as unopposed. If an appeal is filed, Members agree that they will comply with an Award pending an appeal unless and until the FERC issues an order staying its implementation. A summary of ~~such an~~ each application and appeal shall be published in the Association's newsletter or electronic bulletin board. ~~Any Member wishing to respond to such an application shall do so within 14 days. The implementation of an Award shall be stayed pending appeal if the FERC issues an Order agreeing to hear the appeal within 60 days of the initial application for an appeal or if the FERC or a court of competent jurisdiction issues an order staying implementation.~~

12.7 Canadian or Mexican Appeal. Notwithstanding Section 12.5, a disputing Member may apply to the appropriate Canadian or Mexican governmental or regulatory authority to hear an appeal of any Award associated with transmission access or services utilizing facilities located in Canada or Mexico. The standards and procedures for appeals will be no less favorable than those set out in Sections 12.5 and 12.6.

13. NO MANDATORY RETAIL WHEELING.

No Arbitrator shall select and no Member consents to an Award which requires the transmission of electric energy

under circumstances where the FERC is precluded from ordering transmission services pursuant to Subsection 212(h) of the FPA.

14. EFFECT OF BYLAWS.

These Bylaws shall not, in and of themselves, be construed as a tariff, rate schedule or service agreement providing for transmission service. These Bylaws shall not be construed as an agreement of any Member to provide transmission services of a type ~~of~~ or under circumstances that would not be required by the FERC pursuant to FPA Section 211. Nothing in these Bylaws shall be construed as affecting the right ~~of~~ any Member subject to FERC jurisdiction may or may not have to unilaterally make application to FERC for a change in rates or rate methodologies under Sections 205, 206 and 306 of the FPA or the right of any Member not subject to FERC jurisdiction under Sections 205, 206 and 306 of the FPA may or may not have to change rates or rate methodologies; provided such changes result in rates that are consistent with the standards of Section 212 of the FPA. Except as expressly provided herein, these Bylaws specify procedural requirements only and do not constitute a requirement or consent by any Member to any substantive terms or conditions of public utility service. Except as expressly provided for herein, no Member waives any right that it would otherwise have had it not joined the Association but instead proceeded to the FERC directly or was the respondent in a FERC proceeding. All Members are specifically presumed to have preserved their rights to assert to both an Arbitrator and the

FERC on appeal that a proposed transaction does not meet the public interest standard in Section 211 of the FPA. These Bylaws do not replace, modify, supersede or limit any contract, decisions of regulatory agencies or courts of law, or other legally-enforceable entitlement or rights of any Member except as specifically provided herein.

15. AMENDMENTS.

Subject to approval of the FERC, these Bylaws may be amended at any annual or special meeting of the Members.

16. MISCELLANEOUS PROVISIONS.

16.1 Limitation on Liability. Subject to any applicable state and federal law which may specifically limit a Member's ability to enter into this Section, no Member, its directors, members of its governing bodies, officers or employees shall be liable to any other Member or Members for any loss or damage to property, loss of earnings, revenues, personal injury, or any other direct, indirect, or consequential damages or injury which may occur or result from the performance or nonperformance of these Bylaws, including any negligence arising thereunder. It is the express intent, understanding and agreement of the Members that the remedies for nonperformance expressly included in these Bylaws shall be the sole and exclusive remedies available thereunder for any nonperformance of obligations under these Bylaws.

16.2 No Third-Party Beneficiaries. Nothing in these Bylaws shall be construed to create any duty to, any standard

of care with reference to, or any liability to any third party.

17. FERC REVIEW.

17.1 Filing. ~~These Bylaws~~ This Governing Agreement shall be filed with the FERC by one or more public utilities in the Western Interconnection that are subject to the FERC's jurisdiction under Section 205 of the FPA. In such filing the FERC shall be requested to:

(a) Find ~~these Bylaws~~ this Governing Agreement, as written, to be in the public interest;

(b) Expressly approve the provisions of ~~these Bylaws~~ this Governing Agreement, related to obtaining membership (Subsection 3.1), termination of membership (Subsections 3.4 and 3.5) and termination of the Association (Section 18) and find that the FERC notice provisions provided for therein shall be effective to initiate membership, terminate membership and terminate the Association consistent with the FPA and the FERC's rules and regulations thereunder; and

(c) Expressly approve the dispute resolution provision of Section 12 and the procedures for FERC appeal set forth therein.

17.2 Absence of FERC Approval. If the FERC issues an order requiring material changes to ~~these Bylaws~~ this Governing Agreement, or omitting any of the findings or approvals set forth in Subsection 17.1, ~~these Bylaws~~ this Governing Agreement shall have no further force or effect.

18. TERMINATION OF ASSOCIATION.

The Association shall automatically go out of existence and ~~these Bylaws~~ this Governing Agreement shall have no further force or effect at such time, more than one year following the effective date of ~~these Bylaws~~ this Governing Agreement that there are fewer than ten Members who are Transmission Providers or Transmission Users. Such termination shall be effective upon the Secretary providing written notice of such termination to the FERC.

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G.P. Imbrecht, Chairman

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CLEANED VERSION

GOVERNING AGREEMENT

WESTERN REGIONAL TRANSMISSION ASSOCIATION

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PREAMBLE

Voluntary associations, such as this Western Regional Transmission Association (Association), are intended to facilitate the efficient use of existing transmission facilities, coordinate the planning of transmission system expansions and expedite the resolution of disputes.

Pursuant to the Bylaws set forth in this Governing Agreement, Members agree to promote coordinated transmission planning, efficient use of transmission capacity, nondiscriminatory access to transmission facilities and fair pricing for transmission services.

1. PURPOSE.

The Association is a voluntary organization of Transmission Providers, Transmission Users and Commissions located throughout the Western Interconnection. Members have formed the Association to foster the efficient, equitable and reliable use of existing and future transmission facilities and the expeditious and fair resolution of disputes related to transmission access. The Association shall provide a forum for coordination of transmission planning and for the exchange of information to assist Members in meeting their transmission needs. To the extent practicable, the Association shall pursue the activities contemplated hereunder in a manner that avoids duplicating the activities of other transmission planning organizations such as the WSCC and Subregional Coordination Groups.

2. DEFINITIONS.

When capitalized herein, whether in singular or plural, the following terms shall have the following meaning:

2.1 Arbitrator. An individual selected to resolve disputes arising under these Bylaws pursuant to Section 12.

2.2 Arbitration Committee. The Committee described in Subsection 6.7.

2.3 Available Transmission Capacity. That amount of transmission capacity available to a Transmission Provider to provide transmission service to a Transmission User which is not reasonably required to accommodate the Transmission Provider's: (i) Native Load; (ii) existing commitments for firm wholesale sales contracts; (iii) existing contractual and statutory commitments for firm transmission service; (iv) Prudent Reserve and (v) limitations on use of transmission facilities imposed by statutes or regulations.

2.4 Award. A decision of an Arbitrator made pursuant to Subsection 12.3 of these Bylaws.

2.5 Board. The Association's Board of Directors, as described in Section 5.

2.6 Commissions. State or provincial utility regulatory commissions or energy commissions.

2.7 Committee. A Committee of Members established pursuant to these Bylaws or by the Board.

2.8 Existing Facilities. Those transmission facilities owned by a Member or transmission capacity under contract to a Member previously used to transmit electric energy.

2.9 FERC. The Federal Energy Regulatory Commission or a successor agency.

2.10 FPA. The Federal Power Act as it may be amended from time to time.

2.11 Incremental Facilities. Transmission facilities, other than Existing Facilities, that are reasonably required to be used to satisfy a request for transmission service from a Transmission User.

2.12 Interconnected Transmission System. That portion of each Transmission Provider's transmission system utilized for bulk power transactions, generally at voltages of 115 kV and higher.

2.13 Member. Any signatory to this Governing Agreement which is a Transmission Provider, a Transmission User or a Commission operating or located in the Western Interconnection.

2.14 Native Load. Load associated with retail customers and full or partial requirements wholesale customers for which a Transmission Provider, by statute, franchise, contract or federal, state or provincial policy or regulation, has undertaken the obligation to plan, construct and operate its system to provide reliable service.

2.15 Planning Committee. The Committee described in Subsection 9.1.

2.16 Power Marketing Agency. The Western Area Power Administration or the Bonneville Power Administration.

2.17 Prudent Reserve. An amount of transmission capacity set aside for a Transmission Provider's reasonable reliability requirements as determined by the reliability criteria of such Member and consistent with Prudent Utility Practice and regional reliability council criteria, which requirements shall be impartially applied without undue discrimination.

2.18 Prudent Utility Practice. Those practices, methods and acts, including levels of reserves and provisions for contingencies, as may be modified from time to time, that are commonly used in the Western Interconnection to: (i) operate electric systems dependably, reliably, safely, efficiently, economically and in accordance with all applicable laws and governmental rules, regulations and orders; (ii) serve customers; and (iii) prevent material adverse effects on neighboring electric systems.

2.19 Subregional Coordination Groups. Voluntary subregional associations involving Members that may be organized from time to time to exchange information and coordinate local transmission planning in subregions of the Western Interconnection whose governing documents have been approved by the FERC.

2.20 Transmission Provider. Any Member owning or having contractual rights to use transmission facilities located in the Western Interconnection.

2.21 Transmission User. Any Member entitled to apply to the FERC for an order requiring transmission services pursuant to Section 211 of the FPA or any Member that is located outside the United States that would be entitled to apply for such an order were it located within the United States.

2.22 Western Interconnection. The area comprised of those states and provinces in Western Canada, Northern Mexico and the Western United States in which Transmission Providers, which are members of the WSCC, operate synchronously-connected transmission systems.

2.23 WSCC. The Western Systems Coordinating Council.

3. MEMBERSHIP.

3.1 Qualifications. Any entity meeting the definition of a "Member," set forth in Subsection 2.13, shall be admitted to membership in the Association upon executing this Governing Agreement and providing notice of its having done so to the Board and FERC.

3.2 Classifications of Members. Upon being admitted for membership, each Member shall designate which one of the following classifications of Members to which it wishes to be assigned:

a. Major Transmitting Utility

b. Transmission-Dependent Utility

c. Nonutility Supplier

d. Commission

3.3 Membership Responsibilities. Each Member, other than a Commission, shall:

3.3.1 Conduct or participate in joint studies which affect such Member's system; provided, however, no Member shall be required to participate in a study exclusively related to its own system that is initiated by another party unless such study is necessary to respond to a request for transmission service under these Bylaws.

3.3.2 Provide necessary information, data and plans as specified by the Planning Committee to assure coordinated planning of transmission projects.

3.3.3 Provide full and timely responses to requests for transmission service as specified in Section 10.

3.3.4 In regard to transmission service requests at 69 kV or lower voltages, or for other facilities for which the Association does not collect data, provide to the Transmission User, or other Members, system data necessary to conduct system studies, if so desired by the Transmission User or other Members.

3.3.5 Pay its share of administrative and planning costs as described in Section 8 below.

3.3.6 Make its employees available for reasonable periods at no cost to serve as facilitators or Arbitrators of disputes among Members arising out of the application of these Bylaws.

3.3.7 Make transmission services available to other Members consistent with the provisions of Subsection 10.1.

3.4 Withdrawal from Membership. Any Member may withdraw from the Association upon providing written notice of its withdrawal to the Board and the FERC. Notwithstanding such notice of withdrawal, all Awards and requests for transmission service to be provided by such Member in effect or pending as of the date of the receipt of written notice of withdrawal shall be followed to completion pursuant to these Bylaws by the withdrawing Member; provided, however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of these Bylaws. Any Member which has voluntarily withdrawn from the Association may not reapply for Membership for a period of one year from the date of its withdrawal.

3.5 Termination of Membership. At any time that a Member becomes delinquent in the payment of any administrative and operating costs which are incurred during its membership and fails after 90 days of receipt of a written notice to pay such costs, or if the Board finds that a Member has: (i) intentionally or repeatedly violated any Bylaw of the Association, (ii) breached or violated any Award issued pursuant to its membership in the Association, or (iii) willfully obstructed any lawful purpose or activity of the Association, the Board, in its sole discretion, may terminate the Member's membership. The affected Member shall be afforded at least 21 days advance

written notice of any Board meeting at which termination of the Member will be considered and such Member shall have the right to be present and present information to the Board concerning any proposed termination action. Upon termination of membership, all of the Member's voting rights and other rights of membership shall cease. Notwithstanding such notice of termination, all Awards and requests for transmission service to be provided by such Member in effect or pending as of the effective date of termination shall be honored by the terminated Member; provided, however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of these Bylaws. A Member which has been terminated from membership may not reapply for membership for a period of time stated in the Board resolution of termination, which shall not exceed a period of five years.

4. MEETINGS OF MEMBERS.

4.1 Annual Meeting. A meeting of the Members shall be held within 60 days of the effective date of this Governing Agreement and thereafter at least annually, within the Western Interconnection on a date and at a time and place fixed by the Board.

4.2 Notice of Meeting. Written notice of every meeting of the Members shall be prepared and mailed to the last known address of each Member not less than 21 nor more than 60 days before such meeting. Such notice shall state the time and place of the meeting and the meeting agenda.

4.3 Voting. Each Member, other than a Commission, shall be entitled to one vote upon each matter submitted to a vote at a meeting of the Members. Except in regard to the election of Directors, all matters coming before the full Membership shall require the affirmative vote of two-thirds of the Members of each voting Membership classification present at the meeting in order to be adopted.

4.4 Quorum. A majority of the total number of Members with voting rights shall constitute a quorum necessary for the transaction of business at any annual or special meeting of the Members. Those Members present may adjourn from time to time until a quorum is present with no further notice of the meeting required.

5. GOVERNANCE.

5.1 Board of Directors. The Association shall have a Board of Directors comprised of 21 Directors. Directors shall be selected from among the three classifications of voting Members and each such classification shall be entitled to elect and be represented by the following number of Directors:

a.	Major Transmitting Utilities	7
b.	Transmission-Dependent Utilities	7
c.	Nonutility Suppliers	7

5.2 Ex-Officio Directors. Commission Members may select up to three Directors to serve in an ex-officio status on the Board. Such ex-officio directors shall be invited to attend and participate in all meetings of the Board, and Committees,

but shall not have a right to vote on matters coming before the Board or Committees.

5.3 Diversity of Directors. Each Director in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have his or her principal place of business in a different state or province, provided, however, two directors in each of these two classifications may be from California. No more than one Director in any classification may be employed by or be affiliated with any Member. At least three of the Directors in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have their principal place of business in the states of Texas, Arizona, New Mexico, California, Nevada or the states of Mexico and at least three of the Directors in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have their principal place of business in the states of Oregon, Washington, Idaho, Montana, Utah, Wyoming, Colorado or the provinces of British Columbia or Alberta.

5.4 Election of Directors. At each annual meeting of the Members, elections shall be held to fill any vacancies on the Board. Directors shall be selected from within each classification for each position by a plurality vote of the Members of that classification. No person may be nominated for a Director position if his or her election would violate the provisions of subparagraph 5.3. Except as applied to the initial Board, Directors shall be elected for terms of three years and until a

successor is elected and qualified. The initial Board shall determine the length of each Director's term by drawing lots, with three Directors in each classification serving terms of three years, two Directors in each classification serving terms of two years, and two Directors in each classification serving terms of one year.

5.5 Removal of Directors and Vacancies. An individual Director may be removed from office by and at the discretion of a Member employing the Director or by majority vote of the classification of Members represented by the Director to be removed. Whenever a vacancy occurs, a Director's remaining term shall be filled by majority vote of the remaining Directors representing the class of Members whose Director's position became vacant until the next annual meeting at which time it shall be filled by a plurality vote of the classification represented by such Director.

5.6 Annual Board Organizational Meeting. A meeting of the Board shall be held at the conclusion of each annual meeting of the Members for the purpose of electing the officers of the Association for the upcoming year and to transact such other business as may come before the meeting.

5.7 Regular Meetings. Regular meetings of the Board, in addition to its annual meeting, shall be held upon such notice and at such time and place as the Board may determine. The Board may hold meetings by conference call.

5.8 Special Meetings. A special meeting of the Board shall be held whenever called by the President or, during the President's absence or disability, by the Vice President, on notice delivered by first class mail or facsimile at least seven days prior to the meeting. Special meetings shall be called by the President or Secretary in like manner and on like notice on the written request of any four Directors.

5.9 Quorum and Voting. Two-thirds of the Directors in each voting membership classification shall constitute a quorum necessary to the transaction of business at any meeting of the Board. All matters coming before the Board shall require the affirmative vote of two-thirds of each voting class of Directors. By providing written notice to the President, a Director may designate an alternate to attend any Board meeting and such alternate shall have full authority to act and vote in place of the absent Director.

5.10 Action Without a Meeting. Any action which may be taken at a meeting of the Board, or of a Committee, may be taken without a meeting if set forth and approved by a writing signed by all Directors or Committee members, and such action shall be effective on the date on which the last signature is placed on such writing, or such earlier effective date as is set forth therein.

6. DUTIES OF DIRECTORS.

6.1 General Powers. The Board shall manage the business and affairs of the Association, and shall exercise all of the

powers of the Association except such as are by law or these Bylaws conferred upon or reserved to the Members. The Board shall recommend any amendments to the Bylaws for approval by the Members and may adopt such policies, rules, regulations, and actions which are consistent with law and these Bylaws as it may deem advisable.

6.2 Selection of Manager and Agents. The Board shall select and employ a Manager and fix the compensation of such Manager. The Board may terminate the employment of the Manager with or without cause at any time. The Board shall also have authority to authorize the employment of other staff members or retain agents to provide defined activities and services.

6.3 Budgets. The Board shall periodically establish and approve a budget which includes all costs of administration for the Association as well as any anticipated planning costs to be allocated to the Members. Such budgets shall be established and approved not less than annually.

6.4 Accounting System and Audit. The Board shall install and maintain an adequate system of accounts and records. At least annually, the books and accounts of the Association shall be audited by a certified public accountant and the report of such audit shall be made at the next annual meeting of the Members.

6.5 Committees. The Board shall create and, except for the Planning and Arbitration Committees, terminate Committees as it deems appropriate. Membership on all Committees

appointed by the Board shall be allocated among membership classifications and geographic regions on generally the same proportional basis as required for Board membership. The organizational form and term of Committee chairpersons and other positions shall be established by the Board. In regard to each Committee, the Board shall appoint a cochairperson from each of the three membership classifications. The three cochairpersons shall alternate responsibility for chairing the committee as among themselves so that cochairpersons representing any membership classification shall not have such responsibility for more than ten months during any 24-month period. Cochairpersons shall serve terms of three years unless a shorter term is established by the Board. Reasonable advance notice of all Committee meetings shall be given to all Members. Attendance at all Committee meetings shall be open to any Member. Matters coming before Committees shall be adopted only by a majority vote of Committee members present in each membership classification with voting rights.

6.6 Planning Committee. The Board shall appoint a Planning Committee whose function is described in Section 9.1. Three persons representing the Transmission-Dependent Utility, Nonutility Supplier and Commission classifications, respectively, shall be designated by the Planning Committee to serve as liaisons with the planning committees of the WSCC and other planning bodies.

6.7 Arbitration Committee. The Board shall appoint an Arbitration Committee consisting of one representative of each of the three voting Membership classifications. The Arbitration Committee shall have the responsibilities described in Subsection 6.9 and Part 12.2.2 and shall also, from time to time, review the arbitration procedures set forth in these Bylaws and consider proposed changes to be presented to the Board. Members of the Arbitration Committee shall disqualify themselves from participating in any dispute involving such member's employer.

6.8 Other Committees. The Board may authorize such additional committees as it deems necessary to carry out the business of the Association. The Board shall set forth the duties and responsibilities of each such Committee in writing at the time of the creation of the Committee. Each such Committee shall be subject at all times to control and direction of the Board. Copies of the minutes of each Committee meeting, including Planning and Arbitration Committee meetings, shall be mailed to all Directors.

6.9 Qualified Arbitrators. The Board shall establish and from time to time update a list of qualified Arbitrators and facilitators. The list of Arbitrators and facilitators may be subdivided by the Arbitration Committee into specific types of disputes that an Arbitrator or facilitator is considered to be qualified to decide or by subregional areas concerning which an Arbitrator or facilitator has expertise. All arbitrator names

supplied by the Arbitration Committee pursuant to Part 12.2.1 shall be taken at random from the Board-approved list or, at the election of all disputing Members involved in a dispute, subdivisions of that list.

7. OFFICERS AND MANAGER.

7.1 Election of Officers. At each annual meeting of the Board of Directors, the Board shall elect a President, a Vice President, a Secretary and a Treasurer. The President and Vice President shall be chosen from the Directors of the Association. An officer may be removed by the Board whenever in its judgment the best interests of the Association will be served thereby. If any vacancy shall occur among the officers of the Association, it shall be filled by the Board of Directors at its next regular meeting following the vacancy.

7.2 Duties of President. The President shall: (i) preside over all meetings of the Association and the Board; (ii) call special meetings of the Board; and (iii) perform all duties that may be reasonably required by the Association or the Board.

7.3 Duties of Vice President. In the absence or disability of the President, the Vice President shall perform the duties of the President.

7.4 Duties of Secretary. The Secretary shall attend all meetings of the Board and all meetings of the Members and record all votes and keep a complete record of all meetings of the Association and of the Board and shall have general charge

and supervision of the books and records of the Association. The Secretary shall sign all papers pertaining to the Association as may be authorized or directed by the Board. The Secretary shall serve all notices required by law and by these Bylaws including notices of meetings and shall make a full report of all matters and business pertaining to the office to the Members at the annual meeting. The Secretary shall make all reports required by law and shall perform such other duties as may be requested by the Board.

7.5 Duties of Treasurer. The Treasurer shall perform such duties with respect to the finances of the Association as may be prescribed by the Board.

7.6 Duties of Manager. The Manager shall perform such duties and shall exercise such authority as the Board may from time to time vest. The Manager shall put in place and maintain Association newsletters and/or an electronic bulletin board sufficient to keep Members timely informed of events related to Members' activities carrying out the purposes of these Bylaws.

7.7 Compensation. The salary, compensation and other benefits of the Manager and any other staff shall be fixed by the Board. No member of the Board shall receive any compensation or other benefits.

8. MEMBER COSTS.

8.1 Administrative Costs. The administrative costs of the Association shall be allocated among Members on a basis

determined by the Board in advance of each year for which such costs are to be paid.

8.2 Planning Costs. The costs of planning studies or other activities not undertaken in response to a request for transmission services, if undertaken by the Association, shall be generally allocated among the Members benefitting from such activities in proportion to the amounts of transmission capacity in megawatts desired by each participating Member. Specific activities and cost allocations may be memorialized in separate agreements among the participating Members.

9. COORDINATED PLANNING AND ACCESS.

9.1 Planning Committee Functions. The Board shall appoint a Planning Committee. The Planning Committee shall provide a forum for coordination of transmission planning activities within the Association by facilitating the prompt exchange of information among Members through use of a common data base in order to: (i) assist timely responses by Members to requests for transmission service, (ii) assist the development of coordinated transmission plans to serve the needs of all Members, and (iii) support the Association's interface with WSCC, other industry organizations, regulatory bodies and Subregional Coordination Groups. To carry out these responsibilities, the Planning Committee, in conjunction with the WSCC to the extent practicable, shall:

9.1.1 Provide a forum for coordinating transmission plans, sharing system data, facilitating the joint development

of new transmission projects, and meeting the transmission facility planning needs of Members.

9.1.2 Collect, or cause to be made available, Member information, data and transmission plans as determined by the Planning Committee in order for the Association to meet its objectives.

9.1.3 Collect and make available to all Members the internal planning criteria of individual Members.

9.1.4 Ensure that transmission studies and information regarding new transmission facilities are available to all Members who request it.

9.1.5 Prepare, when appropriate, Association planning information reports and maps for government regulatory agencies, reliability councils and others, as requested, including coordinating Transmission Providers' reports to the FERC required by rules promulgated pursuant to Section 213(b) of the FPA.

9.1.6 Refer to Subregional Coordination Groups matters having principally subregional interest.

9.1.7 Periodically review and make recommendations to the Board concerning the procedures for obtaining transmission services provided for in these Bylaws.

9.1.8 Carry out other activities as directed by the Board.

9.2 Planning Information. Each Transmission Provider shall file on an annual basis with the Planning Committee

information regarding its existing and planned Interconnected Transmission System. If Members are also members of a Subregional Coordination Group which assembles planning information, the Planning Committee shall coordinate its data collection activities with the Subregional Coordination Group so as to avoid duplication of effort, to the extent practicable. The Planning Committee shall determine what data are required, including the years for which the data are to be reported and the format of the data, to assure that the objectives of the Association are met. The data submitted by each Transmission Provider for its Interconnected Transmission System shall be in a consistent format, to the extent feasible, with the format established by the WSCC and shall include, at a minimum, data necessary to comply with Section 213(b) of the FPA and rules and regulations promulgated thereunder. All Members shall be able to obtain, through the Association, information necessary for the determination of available transmission capacity on transmission systems of other Members.

9.3 Planning Coordination.

9.3.1 No member shall be required to implement a planning recommendation made by the Planning Committee or the Board; provided, however, no member shall be relieved of its obligation to respond to requests for transmission services as required by these Bylaws or to implement the provisions of an Award.

9.3.2 Members involved in the development of transmission projects that may interconnect two or more utility systems shall provide notice of opportunity to participate in development study work to all Members by posting in the Association's newsletter or electronic bulletin board. Members shall respond in writing to the sponsoring Members within 60 days after notice is posted indicating whether they elect to participate in such studies. Those Members participating in joint project studies shall periodically share the results of the study work with the Planning Committee.

9.3.3 Costs for joint planning studies shall be shared on an equitable basis among those Members participating in the studies. Study costs may include computer costs, staff time, report preparation, report distribution and appropriate overhead costs, as applicable, but shall not include profits for the Member conducting the study.

9.3.4 Arrangements among participating Members for joint studies shall be documented by letter agreement or other appropriate instrument prior to the beginning of the studies.

9.4 Coordination. In order to avoid unnecessary duplication, Transmission Providers shall utilize WSCC reports and data to the maximum extent practicable to fulfill the information reporting requirements set forth in Subsection 9.2. The Planning Committee shall develop standard forms, which Transmission Providers can use to fulfill reporting requirements for the WSCC, the Association, Subregional

Coordination Groups and the FERC. All data collected directly by the Association, or in cooperation with the WSCC, shall be reasonably available to all Members through the Association regardless of its physical location.

9.5 Planning Criteria.

9.5.1 The applicable reliability criteria, standards, guidelines and operating procedures of the North American Electric Reliability Council, the WSCC, other electric reliability councils, and of the individual Transmission Provider shall govern the design and operation of each such Member's transmission system; provided, however, individual Transmission Providers' reliability criteria, standards, guidelines and operating procedures shall be reasonable and consistent with Prudent Utility Practice and shall be consistently applied in determining available transmission capacity or determining what system additions are required.

10. REQUESTS FOR TRANSMISSION SERVICE.

10.1 Service to be Provided. Subject to the provisions of Section 14, each Transmission Provider shall provide transmission service from its Available Transmission Capacity on its Existing Facilities, or from Incremental Facilities where necessary, to any Transmission User on a basis consistent with the FPA, FERC's then-applicable standards and policies and this Governing Agreement and as detailed in the Transmission Provider's applicable tariff, or an agreement negotiated between such Members or established by an Arbitrator, if such

tariff does not exist. Canadian or Mexican Transmission Providers shall provide service based upon policies and pricing methodologies no less favorable to Transmission Users than those established by the FERC. Members not subject to Section 211 of the Federal Power Act agree to provide transmission service on the same basis as those Members that are subject to such requirements.

10.2 Tariff or Agreement Required. Transmission service shall be provided solely under a separate tariff or agreement and these Bylaws shall not, in and of themselves, be construed to be a tariff or service agreement providing for transmission service.

10.3 Request for Service. Each Transmission User desirous of transmission services from a Transmission Provider shall, in each instance, pursue its request for such service pursuant to these Bylaws in lieu of exercising its procedural rights pursuant to Section 211 of the FPA. A Transmission User requesting transmission service shall provide to the Transmission Provider information regarding its request for transmission service, consistent with either the FERC's then-current policy regarding such request (as currently embodied in its "Policy Statement Regarding Good Faith Requests for Transmission Services") or the tariff of the Transmission Provider under which transmission service is sought.

10.4 Response to Request for Firm Transmission Service.

10.4.1 The Transmission Provider shall respond to a request for transmission service from a Transmission User in a manner consistent with Section 212 of the FPA and FERC's then current policies (as presently embodied in its "Policy Statement Regarding Good Faith Requests for Transmission Services").

10.4.2 The Transmission Provider may elect to provide the requested transmission service, or to conduct a study, including any required environmental studies, if such is reasonably required, at the Transmission User's expense, to determine: (i) whether it has sufficient Available Transmission Capacity to provide the requested service initially and for the full term of the request and (ii) what upgrades, additional transmission facilities or interconnections are required to accommodate the requested service. The Transmission Provider's reasonable study costs shall be billed to and paid by the Transmission User in advance based upon the Transmission User's reasonable estimate of such costs. Any reconciliation for over or underpayment shall be done upon completion of the study work. Such study shall be completed within a reasonable time period in accordance with the FERC's then-current policies, as agreed to by the Transmission Provider and Transmission User or, if such Members cannot agree, as determined by the Planning Committee. The Transmission Provider shall be responsible for conducting the study with participation and input from the Transmission User, as mutually agreed to, and the results of

the study shall be made available to the Transmission User, the Coordination Committee, and any other Member requesting it.

10.5 Requests Requiring Upgrades, Additional Facilities or Interconnections.

10.5.1 If the Transmission Provider's report issued at the completion of a study performed pursuant to Subsection 10.4 concludes that the Transmission Provider does not have sufficient Available Transmission Capacity to provide the requested service initially or for the term of the request, it shall include at a minimum: (i) the estimated cost of and cash flow requirements for installing the necessary facilities or providing the interconnection; (ii) the estimated time necessary to build such facilities or provide such interconnection, including the estimated time required for environmental studies, licensing and regulatory approvals, (iii) the estimated incremental capacity added to the transmission system by the additional facilities, (iv) whether the Transmission User will be expected to contribute capital in connection with installing the necessary facilities or providing the interconnection, (v) whether the Transmission User will have the option of contributing capital in connection with installing the necessary facilities or providing the interconnection, and (vi) a description of the rights the Transmission User shall enjoy if it contributes capital to the project.

10.5.2 If the study results demonstrate a need for a transmission interconnection with another entity, the Trans-

mission Provider shall make a good faith effort to arrange a joint study with the other entity to evaluate the impact of such an interconnection. Costs for this additional study shall also be borne by the Transmission User.

10.5.3 If the study results demonstrate a need for and the feasibility of building new facilities or providing an interconnection, the Transmission User may elect to have the required facilities constructed by the Transmission Provider. The Transmission Provider shall be obligated to build the project based upon the conditions outlined in the Transmission Provider's report and an agreement negotiated between the Transmission Provider and the Transmission User, subject only to state and provincial law, the FPA and FERC's standards and policies. The Transmission Provider shall provide notice of the project to all Members through posting in the Association newsletter or electronic bulletin board.

10.6 Requests Involving Only Members of Subregional Coordination Groups.

If a request for transmission service involves only Members who are also members of a Subregional Coordination Group and the governing documents of such Subregional Coordination Group provide for a process for requesting transmission service, the process of the Subregional Coordination Group, as opposed to that set forth in this Section 10, shall be followed. To the extent the governing documents of the Subregional Coordination Group establish different principles

regarding the provision of transmission service, or the pricing thereof, than those of the Association, the principles of the Subregional Coordination Group shall govern as among members of the Subregional Coordination Group.

11. PRICING.

Pricing of transmission service by a Transmission Provider in response to any request for transmission service shall utilize pricing procedures and methodologies for use of Existing Facilities and Incremental Facilities (if applicable) in a manner consistent with the FPA and then-applicable standards and policies of the FERC or as provided for in existing FERC-approved tariffs, where extant. Transmission Providers in Canada or Mexico may rely upon pricing policies of regulatory bodies other than the FERC if such policies are no less favorable to Transmission Users than those of the FERC. Notwithstanding the foregoing, any Transmission Provider may, from time to time, request through a petition for declaratory ruling, or request for rulemaking, that the FERC find a particular form of transmission pricing just and reasonable; provided, however, pending the resolution of such petition or request, established policies shall govern.

12. DISPUTE RESOLUTION.

12.1 Preconditions to Arbitration.

12.1.1 Members shall make best efforts to settle all disputes associated with transmission access or services, including but not limited to, disputes concerning amounts and

location of Available Transmission Capacity, as well as costs, prices, and terms and conditions of transmission service. In the event any such dispute is not settled, any disputing Member may request in writing that the Manager appoint an impartial facilitator from the Association membership to aid the disputing Members in reaching a mutually-acceptable resolution to the dispute and such appointment shall be made within ten days. The facilitator and representatives of disputing Members with authority to settle the dispute shall meet within 21 days after the facilitator has been appointed to attempt to negotiate a resolution of the dispute. A resolution may include referring the matter to a technical body (such as a WSCC Technical Advisory Panel) for resolution or an advisory opinion.

12.1.2 If the disputing Members have not succeeded in negotiating a resolution of the dispute within 30 days after first meeting with the facilitator pursuant to Paragraph 12.1.1, such Members shall be deemed to be at impasse and either Member may commence the arbitration process.

12.1.3 Disputes related to the interpretation or performance of treaties or executed agreements or service schedules that have been approved or accepted for filing by the FERC shall not be subject to Arbitration under these Bylaws unless otherwise agreed by the disputing Members. Disputes only involving Members who are also members of a Subregional Coordination Group whose governing documents provide for a

dispute resolution mechanism shall be resolved in accordance with such dispute resolution mechanism.

12.2 Arbitration Process.

12.2.1 Within 14 days of a disputing Members' request that the arbitration process be commenced, each disputing Member shall submit a statement in writing to the other disputing Members, which statement shall set forth in reasonable detail the nature of the dispute, the issues to be arbitrated, and the proposed Award sought through such arbitration proceedings. To the extent disputing Members do not agree on a form of a required contract for transmission service, each submittal shall include proposed contract language for those issues in dispute. These statements shall constitute the sole submittal of statements for arbitration. A summary of such statement of issues shall be published in the Association's newsletter or electronic bulletin board.

12.2.2 Within ten days following the submission of their statements, the disputing Members shall select an Arbitrator. The arbitration shall be conducted by an Arbitrator familiar with and knowledgeable about the policies and criteria used in the Western Interconnection, transmission systems, and regulatory requirements. If the disputing Members cannot agree upon an Arbitrator, the disputing Members shall take turns striking names from a list of ten qualified individuals supplied by the Arbitration Committee from the list maintained by the Board pursuant to Subsection 6.9 with a

disputing Member chosen by lot first striking a name. The last-remaining name not stricken shall be designated as the Arbitrator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected who is able and willing to serve. No person shall be eligible for selection as an Arbitrator who is a past or present officer, member of the governing body, employee or consultant of any of the disputing Members, or of an entity related to or affiliated with any of the disputing Members or is otherwise interested in the matter to be arbitrated. Any individual designated as an Arbitrator shall make known to the disputing Members any such disqualifying relationship and a new Arbitrator shall be designated in accordance with the provisions of this subparagraph.

12.2.3 The Arbitrator shall determine what arbitration procedures shall apply, consistent with these Bylaws, taking into account the complexity of the issues involved, the extent to which factual matters are disputed and the extent to which the credibility of witnesses is relevant to a resolution. The Arbitrator shall consider all issues underlying a dispute including, if relevant, the reasonableness of a disputing Transmission Provider's reliability criteria; provided, that reliability criteria which are based upon regional reliability council criteria in effect as of January 1, 1994 shall be afforded a rebuttable presumption of reasonableness and

consistency with Prudent Utility Practice by the Arbitrator. The Arbitrator may elect to resolve the disputed matter solely on the basis of written submittals.

12.2.4 The Arbitrator shall take evidence submitted by the disputing Members in accordance with procedures established by the Arbitrator and may request additional information including the opinion of recognized technical experts. Such additional information shall be furnished by the disputing Member or other Members having such information. Disputing Members shall be afforded a reasonable opportunity to rebut any such additional information. Other affected parties may request in writing that the Arbitrator consider additional information and the Arbitrator may consider such additional information, subject to a right of the disputing Members to have a reasonable opportunity to rebut such additional information.

12.3 Award. Within 115 days of his or her selection as Arbitrator, the Arbitrator shall select, by written notice to the disputing Members, the proposed Award of a disputing Member which best meets the terms and intent of these Bylaws and conforms with the FPA and FERC's standards and policies; provided, however, if the Arbitrator concludes that neither proposed Award is consistent with law or applicable FERC policy, the Arbitrator shall specify how each proposed Award is deficient and request that the Disputing Members submit new proposed Awards that cure the deficiency perceived by the

Arbitrator. A written decision explaining the basis for the Award shall be provided by the Arbitrator with the written notice to parties. Both notice and decision shall be published in the Association's newsletter or electronic bulletin board. No Award shall be deemed to be precedent that is binding on an Arbitrator in any other arbitration related to a different dispute.

12.4 Compliance and Costs. Immediately upon the decision by the Arbitrator, except as provided for in Subsection 12.5, the disputing Members shall take whatever action is required to comply with the selected Award to the extent the selected Award does not require regulatory action and shall pursue no avenue of appeal. To the extent the Award requires state or provincial regulatory action, FERC review of an Award involving a Power Marketing Agency or a FERC filing by a Transmission Provider subject to FPA Sections 205 or 206, the affected Member shall submit and support that portion of the Award with the appropriate regulatory authority. Any and all costs associated with the arbitration shall be borne by the Member or Members whose proposed Award was not selected, unless the disputing Members agree to an alternate method of allocating costs.

12.5 FERC Appeal. A disputing Member may apply to the FERC to hear an appeal of any Award only upon the grounds that the Award is contrary to or beyond the scope of these Bylaws or is unjust, unreasonable, unduly discriminatory or preferential

or otherwise inconsistent with the FPA or FERC's standards or policies. Any appeal to the FERC shall be based solely upon the record assembled by the Arbitrator, and deference shall only be afforded to the factual findings of the Arbitrator. The Parties expect that FERC will consider an appeal on the same basis that it reviews initial decisions of Administrative Law Judges pursuant to 5 USC § 557.

12.6 Procedure for Appeals. Following any Award, the Member requesting transmission service before the Arbitrator shall file a fully-documented application with the FERC, pursuant to Section 211 of the FPA, within 14 days of the entry of the Award, including a copy of the Award and the Arbitrator's decision. Such filing may also include an appeal of the Award by the requesting Member, in which case the application shall set forth the basis for the appeal as well as all supporting facts and authority. Any other party to the dispute may appeal the Award, or respond to an appeal by the requesting Member, by filing a response within 14 days of the filing of the application. Such response shall set forth the basis for any appeal or defense of the Award and all supporting facts and authority for such appeal or defense. The Member filing the application may file a defense of the Award in response to any appeal within 14 days of the filing of such appeal. Any appeal of any Award and any defense of an Award shall include a statement indicating whether the FERC should stay the implementation of the Award and what conditions should be

attached to any such stay, together with supporting arguments. The Member appealing an Award shall cause the entire record of the arbitration to be filed with the FERC, with a copy to all other disputing Members within 14 days of initiating the appeal. If no appeal of the Award is made in the application or any response thereto, the FERC shall grant the application as unopposed. If an appeal is filed, Members agree that they will comply with an Award pending an appeal unless and until the FERC issues an order staying its implementation. A summary of each application and appeal shall be published in the Association's newsletter or electronic bulletin board.

12.7 Canadian or Mexican Appeal. Notwithstanding Section 12.5, a disputing Member may apply to the appropriate Canadian or Mexican governmental or regulatory authority to hear an appeal of any Award associated with transmission access or services utilizing facilities located in Canada or Mexico. The standards and procedures for appeals will be no less favorable than those set out in Sections 12.5 and 12.6.

13. NO MANDATORY RETAIL WHEELING.

No Arbitrator shall select and no Member consents to an Award which requires the transmission of electric energy under circumstances where the FERC is precluded from ordering transmission services pursuant to Subsection 212(h) of the FPA.

14. EFFECT OF BYLAWS.

These Bylaws shall not, in and of themselves, be construed as a tariff, rate schedule or service agreement providing for

transmission service. These Bylaws shall not be construed as an agreement of any Member to provide transmission services of a type or under circumstances that would not be required by the FERC pursuant to FPA Section 211. Nothing in these Bylaws shall be construed as affecting the right any Member subject to FERC jurisdiction may or may not have to unilaterally make application to FERC for a change in rates or rate methodologies under Sections 205, 206 and 306 of the FPA or the right of any Member not subject to FERC jurisdiction under Sections 205, 206 and 306 of the FPA may or may not have to change rates or rate methodologies; provided such changes result in rates that are consistent with the standards of Section 212 of the FPA. Except as expressly provided herein, these Bylaws specify procedural requirements only and do not constitute a requirement or consent by any Member to any substantive terms or conditions of public utility service. Except as expressly provided for herein, no Member waives any right that it would otherwise have had it not joined the Association but instead proceeded to the FERC directly or was the respondent in a FERC proceeding. All Members are specifically presumed to have preserved their rights to assert to both an Arbitrator and the FERC on appeal that a proposed transaction does not meet the public interest standard in Section 211 of the FPA. These Bylaws do not replace, modify, supersede or limit any contract, decisions of regulatory agencies or courts of law, or other

legally-enforceable entitlement or rights of any Member except as specifically provided herein.

15. AMENDMENTS.

Subject to approval of the FERC, these Bylaws may be amended at any annual or special meeting of the Members.

16. MISCELLANEOUS PROVISIONS.

16.1 Limitation on Liability. Subject to any applicable state and federal law which may specifically limit a Member's ability to enter into this Section, no Member, its directors, members of its governing bodies, officers or employees shall be liable to any other Member or Members for any loss or damage to property, loss of earnings, revenues, personal injury, or any other direct, indirect, or consequential damages or injury which may occur or result from the performance or nonperformance of these Bylaws, including any negligence arising thereunder. It is the express intent, understanding and agreement of the Members that the remedies for nonperformance expressly included in these Bylaws shall be the sole and exclusive remedies available thereunder for any nonperformance of obligations under these Bylaws.

16.2 No Third-Party Beneficiaries. Nothing in these Bylaws shall be construed to create any duty to, any standard of care with reference to, or any liability to any third party.

17. FERC REVIEW.

17.1 Filing. This Governing Agreement shall be filed with the FERC by one or more public utilities in the Western

Interconnection that are subject to the FERC's jurisdiction under Section 205 of the FPA. In such filing the FERC shall be requested to:

(a) Find this Governing Agreement, as written, to be in the public interest;

(b) Expressly approve the provisions of this Governing Agreement, related to obtaining membership (Subsection 3.1), termination of membership (Subsections 3.4 and 3.5) and termination of the Association (Section 18) and find that the FERC notice provisions provided for therein shall be effective to initiate membership, terminate membership and terminate the Association consistent with the FPA and the FERC's rules and regulations thereunder; and

(c) Expressly approve the dispute resolution provision of Section 12 and the procedures for FERC appeal set forth therein.

17.2 Absence of FERC Approval. If the FERC issues an order requiring material changes to this Governing Agreement, or omitting any of the findings or approvals set forth in Subsection 17.1, this Governing Agreement shall have no further force or effect.

18. TERMINATION OF ASSOCIATION.

The Association shall automatically go out of existence and this Governing Agreement shall have no further force or effect at such time, more than one year following the effective date of this Governing Agreement that there are fewer

than ten Members who are Transmission Providers or Transmission Users. Such termination shall be effective upon the Secretary providing written notice of such termination to the FERC.

AGENDA
WESTERN TRANSMISSION GROUP MEETING

November 15, 1993 <<>> 9:00 am - 5:00 pm
November 16, 1993 <<>> 9:00 am- 4:00 pm

1. INTRODUCTIONS

2. FINALIZE AGENDA

3. DISCUSSION OF WRTA GOVERNING AGREEMENT (WEST-WIDE)

   - Review of proposed approaches on:
     (1) Subregional Organizations
     (2) Planning and WSCC
     (3) Conditions of Service
     (4) Dispute Resolution
     (5) Rights Under FPA
     (6) Other Details

   - Next Steps For West-Wide Proposal

4. STATE REGULATORY PARTICIPATION

   - Comments from Charles R. Imbrecht
     Chairman, California Energy Commission

   - Feedback from RTG Workshop at Monterey WEIB Meeting

5. DISCUSSION OF ALTERNATIVES TO A WEST-WIDE ORGANIZATION

   - West-Wide "Umbrella" RTG with WSCC Regional Planning

   - A reciprocity agreement between independent RTGs

Proposed Resolution of Outstanding West-Wide RTG Bylaw Issues

	Issue	Proposed Resolution	Page Reference[1]
1	Are Bylaws a contract?	Yes. Change name to "Governing Agreement"	1
2	Duplication of effort.	To be avoided to the maximum extent practicable.	1, 19, 21, 22
3	Tax-exempt financing constraints.	To be considered on a case-by-case basis in context of determining "Available Transmission Capacity."	2
4	Basis for "recognition" of Subregional Coordination Groups.	Only FERC approval of governing documents of Subregional Coordination Group required.	4
5	Distribution of terms of initial Board members.	Staggered terms distributed evenly among classes.	11
6	Committee membership.	All committees open to all Members with cochairpersons from three classifications rotating chair responsibilities.	14
7	Committee voting.	Majority vote of members of each classification who are present.	15
8	Arbitration Committee Member conflicts.	Disqualification required.	15
9	When subjects of arbitrator list are to be used.	At election of all disputing Members.	16

[1] Page references are to 11/5/93 Relined Version

	Issue	Proposed Resolution	Page Reference
10	Administrative cost allocation among Members.	Formula to be established each year by the Board.	19
11	Availability of planning data.	All information available to all Members through the Association.	20, 21, 23
12	"Ownership-like" rights.	Determined on case-by-case basis consistent with then-prevailing FERC policy.	26
13	Requests involving only Members of a Subregional Coordination Group.	Procedures of Subregional Coordination Group govern.	27
14	Pricing for transmission services involving only Members of a Subregional Coordination Group.	Policies of Subregional Coordination Group govern.	28
15	Disputes involving only Members of a Subregional Coordination Group.	Procedures of Subregional Coordination Group govern.	30
16	Result if both proposed arbitration awards are flawed.	Arbitrator to request revised proposals.	33
17	FERC appeal.	FERC not afforded discretion to not hear an appeal.	34

	Issue	Proposed Resolution	Page Reference
18	Basis for FERC appeal.	Limited to arbitration record, deference only to factual findings, review on the same basis as an ALJ initial decision.	34
19	Obtaining FERC jurisdiction.	Each award filed with the FERC pursuant to § 211 by the Member requesting service.	35
20	Stay pending appeal.	In FERC's discretion.	36
21	Appeals involving facilities outside the United States.	Heard by "appropriate body" subject to same standards and procedures applicable to FERC review.	36
22	§ 205 rights.	Left open whether § 205 applies in a § 211 context.	37
23	Public agency right to change rates.	Same treatment as § 205 rights.	37
24	Reservation of rights.	All rights reserved except as specifically provided for in Bylaws.	38

Western Transmission Group

15-16 November, 1993 -- Los Angeles, California

Name	Organization	Mailing Address City, St Zip	Phone	Fax
Steven Walton	PacifiCorp	1407 W. North Temple, 320 PTO Salt Lake City, Utah	(801) 220-4057	(801) 220-2842
Fred Hammerquist	"	920 SW 6TH Portland, Ore 97204	(503) 464-6462	(503) 464-5226
George Galloway	Stoel Rives Boley Jones & Grey (PacifiCorp)	900 SW Fifth Avenue Portland, Ore 97205	(503) 294-9306	(503) 220-2480
Carl Imparato	Pacific Gas & Electric	77 BEALE - RM 2387 San Francisco CA 94106	415-973-4325	415-972-2918
Bob Lambert	Pacific Gas & Electric	77 Beale St Room 2305 San Francisco, Ca 94106	415-973-1322	415-972-2918
Doug Larson	Western Interstate Energy Board	600 17th St. Suite 1704 S. Denver CO 80202	303/573 8910	303/573 9107
Daniel Nix	CALIFORNIA ENERGY COMMISSION	1516 NINTH ST. SACRAMENTO, CA 95814	916.654.4861	916.654.4753
Michael Early	DSIS	1300 SW 5th Portland OR 97201	503 221-7400	503 241 0950
Marilyn Eiler	Western Area Power Administration	P.O. Box 6457 (615 S. 43 Ave) Phoenix, AZ 85005	(602) 352-2650	(602) 352-2630
Rebecca DeCorse	Tucson Electric Power Co.	P O BOX 711 Tucson, AZ 85702	(602) 745-3374	(602) 571-4014
Vera Rappuhn	Plains Electric	PO Box 6551 Albuquerque New Mexico 87197	(505) 889-7664 -7234	(505) 889-7636
Jolie Ault	Pub Serv of NM	ALVARADO SQUARE ALBUQUERQUE, NM 87158	505 848 2579	848-2963

Western Transmission Group

15-16 November, 1993 -- Los Angeles, California

Name	Organization	Mailing Address City, St Zip	Phone	Fax
Ralph Lusby	Arizona Public Service	400 N. 5 st Phoenix, AZ 85072	602 250-3161	602 250-3813
Dan Klempel	Basin Electric Power Cooperative	1717 East Interstate Ave. Bismarck, N.D. 58501	701-223-0441	701-224-5332
Chuck Durick	Idaho Power Co	PO Box 70 Boise ID 83707	208 383-2450	208 368-6905
Tom Faull	IPUC	Statehouse Mail Boise ID 83720	208-334-0351	Fax Call me.
Ron Connelly	USBR	P.O. Box 61470 Boulder City NV 89006-1470	702-293-8111	702-293-8042
Nov. 15 & 16 Dee Tagliavia	Enron Power Marketing	P.O. Box 1188 EB 3348 Houston, TX 77251-1188	(713) 853-7327	(713) 646-5800
DICK ROSE	PORTLAND GENERAL ELECTRIC	121 SW SALMON ST. PORTLAND, OR. 97204	(503) 464-7032	(503) 464-2538
MARLENE HUNTSINGER	"	"	(503) 464-7164	(503) 464-2465
BUD EARLEY	FERC	825 N. CAPITOL ST., NE WASHINGTON, DC 20426	202-208-0023	202-208-1010
Steve Herod	FERC	"	202-208-1200	202-208-0980
LINDA HENSLEY	SMUD	PO 15830 Sacramento CA 95852	916 732 5364	916 732 6423
Jerry JORDAN	Ca Mun Util Assoc	1225 8th #440 Sacramento, 95814	(916) 441-1733	(916) 441-4053

Western Transmission Group

15-16 November, 1993 -- Los Angeles, California

Name	Organization	Mailing Address City, St Zip	Phone	Fax
Stu Wilson	Calif. Munic. Util. Assn.	1225 8th St. #440 Sacramento, CA 95814	(916) 441-1733	(916) 441-4053
Fred Yanney	Mudge Rose	333 South Grand Ave. Fl 21 Los Angeles, CA 90701	(213) 229-2315	(213) 680-1358
Jim McClusky	Calif Energy Comm	1516 9th St, MS-46 Sacramento Ca 95814	916 654 3911	
TOM FLYNN	CA. ENERGY COMM.	1516 NINTH ST, MS-46 SACRAMENTO, CA 95814	916/654-5049	916/654-4304
Jim BECK	RES. MGMT INTL, INC.	PO BOX 15516 SACRAMENTO 95852	916/852-1300	916/852-1073
WALTER HALL	LADWP	P.O. BOX 111 rm 1129 LA CA 90051	(213) 367 0308	(213) 367 0457
Alan Vallow	LADWP	" Rm 1121D	(213) 367-0220	" "
George Morrow	PASADENA	150 S Los Robles #200 Pasadena CA 91768	(818) 405-4154	(818) 792-5658
JANIS LEHMAN	ANAHEIM	201 S. ANAHEIM BLVD ANAHEIM CA 92805	(714) 254-4278	(714) 254-4140
Mark Mitchell	Salt River Project	P.O. Box 52025 Phoenix, Az 85072-2025	(602) 236-3526	(602) 236-2201
Mary McKenzie	CA PUB. UTIL. Comm	505 Van Ness Ave San Francisco CA 94102	415 703 2760	415 703 2262
Steve Lorton	BPA	P.O. Box 3621, Portland OR 97208	(503) 230-4595	(503) 230-7405

Western Transmission Group

15-16 November, 1993 -- Los Angeles, California

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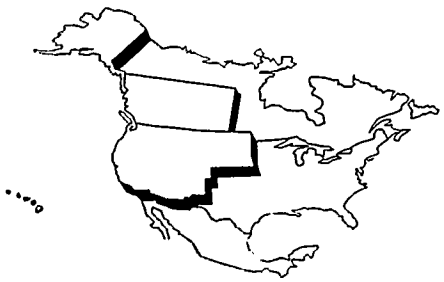
Dean Perry	BPA	P.O. Box 3621 Portland Or 97208	(503) 230-4411	(503) 230-3212
Rich Nassief	Northwest Power Pool	26 SW. Salmon ST. STE 400 Portland, OR. 97204	503-464-2807	503-464-2819
Bill McEwan	City of Colorado Springs	PO Box 1103, Mail Code 610 Colorado Springs CO 80947	719-636-5363	719-444-2566
Lon Peters	Public Power Council	500 NE Multnomah, #729 Portland ~~97232~~ 97232	503.232.2427	503.239.5959
Chris Ellison	IEP/Cal. Dept. of General Services	2311 Capitol Ave Sacramento, CA 95818	(916) 447-2166	(916) 447-3512
Ron Nunnally	So. Calif Edison	P.O. Box 800 Rosemead CA 91770	(818) 302-1653	(818) 302-9647
Jim Kritikson	↓	↓	818/302-8580	818/302-9647
Art Lane	Seattle City Light	Room 420, 1111 3rd Ave Bldg Seattle WA 98104	(206) 386-4561	(206) 386-4555
Marshall Empey	UAMPS	8722 South 300 West Sandy Utah 84070	801-566-3938	801-561-2687
Nov 16 F.R. Peterson	SRP	PO Box 52025 Phx, Az 85072-2025	602-236-2205	602-236-2201
D.J. Melvold	LADWP	P.O. Box 111, Rm 1129 Los Angeles, CA 90051	213-367-0420	213-367-0457
↓ Jeff Ghilarducci	Sedwest	1455 Frazee Road, 9th Flr San Diego, CA 92108	619 293-3340	619 293-3347

Western Transmission Group

15-16 November, 1993 -- Los Angeles, California

Name	Organization	Mailing Address City, St Zip	Phone	Fax
Bob Mooney	IIEC	1161 W River #200 Boise Id 83702	208 338 2604	208 338 2697



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Douglas C. Larson
Executive Director

MEMORANDUM

TO: Committee on Regional Electric Power Cooperation

FROM: Jim Byrne (UT)

DATE: February 16, 1994

SUBJECT: **Report on RTG Developments**

WRTA Developments

On February 8, a general industry meeting on the bylaws for a westwide regional transmission group (Western Regional Transmission Association — WRTA) was held in Portland. The last general meeting was held in November and planning and drafting subcommittees have been operating during the interim between the meetings.

In addition to reviewing the latest draft bylaws, an effort was made to reach closure on the drafting effort by identifying potential "charter" members of WRTA. Fine tuning of the bylaws would be undertaken by those parties indicating a likelihood that they will join WRTA. Self-identified "charter" members were: Idaho Power; Pacific Gas & Electric; PacifiCorp; BPA; City of Colorado Springs; California Independent Energy Producers; Sacramento Municipal Utility District; Northern California Power Agency; City of Anaheim; Enron Gas Services Corporation; WAPA; San Diego Gas & Electric; Clark County PUD; Consolidated Pumped Storage; and Fletcher-Challenge.

All parties to the discussion were asked to submit their proposed bylaw language changes by February 18. A marathon drafting session among the "charter" members is set for February 23-25 in Portland. The group hopes to have a polished draft of the bylaws by March 18 which would be taken to their respective management for approval. Under this ambitious schedule, the bylaws would be filed with the FERC in April.

600 17th Street, Suite 1704 South Tower
Denver, Colorado 80202-5447
303/573-8910 FAX 303/573-9107

Key issues raised at the meeting included:

- The relationship between subregional RTGs (particularly the Southwest Regional Transmission Association — SWRTA) and WRTA;
- Granting of ownership-like rights to parties requesting transmission;
- RTG costs and the allocation of those costs among members;
- Whether Available Transmission Capacity can be reserved for forecasted load growth;
- The relationship between WRTA and WSCC, including whether WRTA will drive planning requirements under the RTG or whether WSCC planning initiatives will drive WRTA planning; and
- Whether existing transmission tariffs with the FERC are grandfathered and are the basis for setting the price for requested transmission (they are not).

One of the major issues has been the relationship between WRTA and WSCC. WRTA has suggested that it contract with WSCC for planning services and asked WSCC to modify the composition of its executive committee to reflect the composition of the WRTA executive committee (1/3 transmission-owning utilities; 1/3 transmission-dependent utilities; and 1/3 non-utility suppliers). The enclosed draft letter responding to the WRTA proposal was circulated. WSCC's Regional Planning Policy Committee met in Phoenix on February 10 to review the draft letter and will make a recommendation to the WSCC executive committee on March 8-9.

Subregional RTG Actions

Northwest parties met on February 7 to review draft bylaws. Reports from the meeting indicate a variety of motives for Northwest parties to develop RTG bylaws, including the need to address subregional planning issues and the need to develop a backup if WRTA does not advance. An updated draft of the Northwest bylaws is expected this month.

The **SWRTA** group has completed its draft bylaws and is visiting state commissions to discuss them.

The **WATSCO** group has completed draft bylaws and a meeting of principals was held earlier this month to try to sign up members. WATSCO has also briefed the California PUC and Energy Commission.

A side-by-side comparison of the latest WATSCO, SWRTA and WRTA bylaws is enclosed.

State/Provincial Role in WRTA

At its April 27-29 meeting, the Committee on Regional Electric Power Cooperation (CREPC) will be examining in depth the linkage between utility-specific plans and regional transmission planning by WSCC or one or more RTGs. However, the current draft of the WRTA bylaws provides some linkage. The draft bylaws provide that the Board of Directors of WRTA can remove a member "if the Board finds that governmental or judicial bodies have imposed requirements or restrictions on such Member which materially impeded such Member's ability to fulfill its obligations pursuant to this Governing Agreement." This may be a first step in trying to link RTG decisions to state/provincial decisions. There may be other ways of connecting RTG activities with state and provincial actions that need to be explored at the April 28 workshop (e.g., requiring utilities in their resource plans to explain how the various resource options fit with regional transmission plans).

However, given the schedule for developing the WRTA bylaws and, specifically, WRTA's call for comments by February 18, I would like to suggest the following language to clarify the role of the states/provinces.

Redefine commissions to read:

2.6 Commissions. State or provincial utility regulatory commissions or energy commissions. State or provincial facility siting agencies or the Northwest Power Planning Council may participate as "Commission" Members.

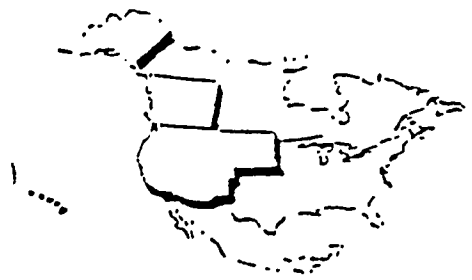
Rationale: I believe we need to ensure the full range of state/provincial regulatory agencies involved in planning, regulating and siting activities will be eligible for membership. Three ex-officio members to the WRTA executive committee will come from "Commissions."

Please call me, 801\530-6763) or Doug Larson (WIEB), 303\573-8910 if you have any views on this amendment.

Recognizing that we cannot make other substantive suggestions for WRTA bylaw amendments at this time, I suggest that time be set aside at the Scottsdale meeting on April 27-29 to consider how states will utilize the results of RTG planning. The planning workshop on April 28 will examine linkages between current utility IRPs, transmission planning and regional resources. I suggest that we specifically discuss how state/provincial agencies should participate

in RTG transmission planning considerations and how (whether) states should recognize (acknowledge/approve/give deference to) RTG transmission planning and access decisions. Please be discussing these topics at your agency prior to the Scottsdale meeting.

Enclosures: WATSCO, SWRTA, WRTA bylaw side-by-side
Draft summary of February 8 WRTA meeting
Draft letter from WSCC to WRTA



Western Interstate Energy Board/ WINB

January 22, 1993

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Richard Anderson
Chairman

Douglas C. Larson
Executive Director

The Honorable Martin L. Allday, Chairman
c/o Office of the Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

RE: Docket No. RM93-3-000

Dear Chairman Allday:

The Committee on Regional Electric Power Cooperation is responding to the Commission's request for comments on a Regional Transmission Group proposal. The Committee includes the regulatory commissions and governor's energy offices from eleven western states and representatives from the two Canadian provinces in the Western Systems Coordinating Council region. The purpose of the Committee is to foster interstate cooperation on issues which impact the western electricity system.

The Committee has examined the concept of Regional Transmission Groups (RTGs) with utilities that are involved in discussions of the formation of four such RTGs in the western region. The Committee believes that RTGs may offer solutions to western transmission planning and access issues which are more efficient and responsive to regional needs than generic national solutions without regard to regional diversity.

Therefore, the Committee supports the establishment of a western Regional Transmission Group(s). See attached resolution.

The Committee looks forward to working with the FERC, as well as the national Association of Regulatory Utility Commissioners and state agencies responsible for transmission line siting, to make RTGs a reality. The Committee has historically urged FERC to involve states in its decisions through the use of joint boards. Joint boards may be an effective means to further the development of RTGs which meet regional needs.

Sincerely,

Bil Tucker

Bil Tucker, Chairman
Committee on Regional Electric Power Cooperation
and
Chairman, Wyoming Public Service Commission

Enclosure

600 17th Street, Suite 1704 South Tower
Denver, Colorado 80202-5401
303/573-8910 FAX 303/573-9107

Resolution on
Regional Transmission Associations in the West

WHEREAS, the Committee on Regional Electric Power Cooperation (Committee) includes representatives of the state utility regulatory commissions and Governors' energy advisors of the eleven western states in the Western Systems Coordinating Council (WSCC) region; and

WHEREAS, the Committee has been evaluating regional transmission issues in the West for almost ten years; and

WHEREAS, the WSCC, with the urging and support of the Committee, has been moving in the direction of increasing its data gathering, modeling and analysis capability related to the western interconnected transmission grid, and has opened its membership to all utilities and electric power generators; and

WHEREAS, within the WSCC, several groups have been actively planning for the formation of a Regional Transmission Association(s); and

WHEREAS, the enactment of the Energy Policy Act of 1992 provides authority for the Federal Energy Regulatory Commission (FERC) to order transmission access, but does not explicitly authorize RTAs; and

WHEREAS, the Committee believes that regional solutions to regional transmission planning and access issues may be more efficient and responsive to regional needs than generic national solutions applied without regard to regional diversity.

NOW, THEREFORE BE IT RESOLVED that the Committee on Regional Electric Power Cooperation supports efforts to establish a western Regional Transmission Association(s) and agrees to work with the National Association of Regulatory Utility Commissioners, representatives of state agencies responsible for transmission line siting, and the Federal Energy Regulatory Commission to develop a coordinated FERC and state approach to RTAs that addresses the responsibilities and authorities of both FERC and the states.

Adopted by the Committee on Regional Electric Power Cooperation

Resource Information

A. **Positions of the Committee on Regional Electric Power Cooperation**

B. **Federal Power Act** (selected sections)

C. **FERC Policy Statement Regarding Regional Transmission Groups**

D. FERC Inquiry Concerning the Commission's **Pricing Policy for Transmission Services** Provided by Public Utilities Under the Federal Power Act

E. FERC Policy Statement **Regarding Good Faith Requests for Transmission Services and** Responses by Transmitting utilities under Sections 211(a) and 213(a) of the Federal Power Act, as Amended and Added By the Energy Policy Act of 1992

F. FERC final rule on **New Reporting Requirements** Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibiliteis under the Energy Policy Act of 1992, and Conforming and Other Changes to Form No. FERC - 714

WSCC comments on proposed rule

G. **FERC Interregional Transmission Coordination Forum decision**

H. **Western Regional Transmission Association Bylaws**

I. **WATSCO Bylaws**

J. SWRTA Bylaw (to be added)

K. Public Service Company of Colorado and Tri-State Generation and Transmission **"Electric Transmission Service Policy Statement"**

L. Northwest Bylaws (to be added)

M. "Establishing Firm Transmission Rights Using a 'Rated System Path' Model" by Steven L. Walton

Excerpts of the Federal Power Act

Sections 205-213

Rates and Charges; Schedules; Suspension of New Rates

Sec. 205. (a) All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classification, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Unless the Commission otherwise orders, no change shall be made by any public utility in any such rates, charges, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commisison may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f)(1) Not later than 2 years after the date of the enactment of this subsection and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are—

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to—

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause, if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.

.01 Subsections (a)(c)—Act of June 10, 1920; Subsection (d)—Act of June 10, 1920, as amended by P.L. 95-617, November 9, 1978; Subsection (e)—Act of June 10, 1920; Subsection (f)—P.L. 95-617, November 9, 1978.

Subsection (d) was amended by P.L. 95-617 by striking out "thirty" each place it appeared and substituting "sixty".

Subsection (f) was added by P.L. 95-617, November 9, 1978.

Fixing Rates and Charges; Determination of Cost of Production or Transportation

Sec. 206. (a) Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charges, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. Any complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate, charge, classification, rule, regulation, practice, or contract then in force, and the reasons for any proposed change or changes therein. If, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by order the time and place of such hearing and shall specify the issues to be adjudicated.

(b) Whenever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier than the date 60 days after the filing of such complaint nor later than 5 months after the expiration of such 60-day period In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date 60 days after the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the expiration of such 60-day period. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under section 205 of this Act and otherwise act as speedily as possible. If no final decision is rendered by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, whichever is earlier, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion of any proceeding under this section, the Commission may order the public utility to make refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: *Provided*, That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceed-

ing was not resolved within the fifteen month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

(c) Notwithstanding subsection (b), in a proceeding commenced under this section involving two or more electric utility companies of a registered holding company, refunds which might otherwise be payable under subsection (b) shall not be ordered to the extent that such refunds would result from any portion of a Commission order that (1) requires a decrease in system production or transmission costs to be paid by one or more of such electric companies; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the costs to be paid by other electric utility companies of such registered holding company: *Provided*, That refunds, in whole or in part, may be ordered by the Commission if it determines that the registered holding company would not experience any reduction in revenues which results from an inability of an electric utility company of the holding company to recover such increase in costs for the period between the refund effective date and the effective date of the Commission's order. For purposes of this subsection, the terms "electric utility companies" and "registered holding company" shall have the same meanings as provided in the Public Utility Holding Company Act of 1935, as amended.

(d) The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

.01 Act of June 10, 1920, as amended by P.L. 100-473, October 6, 1988.

Section 206 read as follows until its amendment by P.L. 100-473, October 6, 1988:

Sec. 206. (a) Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charges, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

(b) The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

Furnishing of Adequate Service

Sec. 207. Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: *Provided*, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel the public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

[¶ 5258]

Ascertainment of Cost of Property

Sec. 208. (a) The Commission may investigate and ascertain the actual legitimate cost of the property of every public utility, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation, and the fair value of such property.

(b) Every public utility upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.

[¶ 5259]

Use of Joint Boards; Cooperation with State Commissions

Sec. 209. (a) The Commission may refer any matter arising in the administration of this Part to a board to be composed of a member or members, as determined by the Commission, from the State or each of the States affected or to be affected by such matter. Any such board shall be vested with the same power and be subject to the same duties and liabilities as in the case of a member of the Commission when designated by the Commission to hold any hearings. The action of such board shall have such force and effect and its proceedings shall be conducted in such manner as the Commission shall by regulations prescribe. The board shall be appointed by the Commission from persons nominated by the State commission of each State affected, or by the Governor of such State if there is no State commission. Each State affected shall be entitled to the same number of representatives on the board unless the nominating power of such State waives such right. The Commission shall have discretion to reject the nominee from any State, but shall thereupon invite a new nomination from that State. The members of a board shall receive such allowances for expenses as the Commission shall

provide. The Commission may, when in its discretion sufficient reason exists therefor, revoke any reference to such a board.

(b) The Commission may confer with any State commission regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission; and the Commission is authorized, under such rules and regulations as it shall prescribe, to hold joint hearings with any State commission in connection with any matter with respect to which the Commission is authorized to act. The Commission is authorized in the administration of this Act to avail itself of such cooperation, services, records, and facilities as may be afforded by any State commission.

(c) The Commission shall make available to the several State commissions such information and reports as may be of assistance in State regulation of public utilities. Whenever the Commission can do so without prejudice to the efficient and proper conduct of its affairs, it may upon request from the State make available to such State as witnesses any of its trained rate, valuation, or other experts, subject to reimbursement to the Commission by such State of the compensation and traveling expenses of such witnesses. All sums collected hereunder shall be credited to the appropriation from which the amounts were expended in carrying out the provisions of this subsection.

[¶ 5260]

Certain Interconnection Authority

Sec. 210. (a)(1) Upon application of any electric utility, geothermal power producer (including a producer which is not an electric utility), Federal power marketing agency, qualifying cogenerator, or qualifying small power producer, the Commission may issue an order requiring—

(A) the physical connection of any cogeneration facility, any small power production facility, or the transmission facilities of any electric utility, with the facilities of such applicant,

(B) such action as may be necessary to make effective any physical connection described in subparagraph (A), which physical connection is ineffective for any reason, such as inadequate size, poor maintenance, or physical unreliability,

(C) such sale or exchange of electric energy or other coordination, as may be necessary to carry out the purposes of any order under subparagraph (A) or (B), or

(D) such increase in transmission capacity as may be necessary to carry out the purposes of any order under subparagraph (A) or (B).

(2) Any State regulatory authority may apply to the Commission for an order for any action referred to in subparagraph (A), (B), (C), or (D) of paragraph (1). No such order may be issued by the Commission with respect to a Federal power marketing agency upon application of a State regulatory authority.

(b) Upon receipt of an application under subsection (a), the Commission shall—

(1) issue notice to each affected State regulatory authority, each affected electric utility, each affected Federal power marketing agency, each affected owner or operator of a cogeneration facility or of a small power production facility, and to the public,

(2) afford an opportunity for an evidentiary hearing, and

(3) make a determination with respect to the matters referred to in subsection (c).

(c) No order may be issued by the Commission under subsection (a) unless the Commission determines that such order—

(1) is in the public interest,

(2) would—

(A) encourage overall conservation of energy or capital,

(B) optimize the efficiency of use of facilities and resources, or

(C) improve the reliability of any electric utility system or Federal power marketing agency to which the order applies, and

(3) meets the requirements of section 212.

(d) The Commission may, on its own motion, after compliance with the requirements of paragraphs (1) and (2) of subsection (b), issue an order requiring any action described in subsection (a)(1) if the Commission determines that such order meets the requirements of subsection (c). No such order may be issued upon the Commission's own motion with respect to a Federal power marketing agency.

(e)(1) As used in this section, the term "facilities" means only facilities used for the generation or transmission of electric energy.

(2) With respect to an order issued pursuant to an application of a qualifying cogenerator or qualifying small power producer under subsection (a)(1), the term "facilities of such applicant" means the qualifying cogeneration facilities or qualifying small power production facilities of the applicant, as specified in the application. With respect to an order issued pursuant to an application under subsection (a)(2), the term "facilities of such applicant" means the qualifying cogeneration facilities, qualifying small power production facilities, or the transmission facilities of an electric utility, as specified in the application. With respect to an order issued by the Commission on its own motion under subsection (d), such term means the qualifying cogeneration facilities, qualifying small power production facilities, or the transmission facilities of an electric utility, as specified in the proposed order

Certain Wheeling Authority

Sec. 211.

(a) Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant. Upon receipt of such application, after public notice and notice to each affected State regulatory authority, each affected electric utility, and each affected Federal power marketing agency, and after affording an opportunity for an evidentiary hearing, the Commission may issue such order if it finds that such order meets the requirements of section 212 [16 USCS § 824k], and would otherwise be in the public interest. No order may be issued under this subsection unless the applicant has made a request for transmission services to the transmitting utility that would be the subject of such order at least 60 days prior to its filing of an application for such order.

(b) Reliability of electric service. No order may be issued under this section or section 210 [16 USCS § 824i] if, after giving consideration to consistently applied regional or national reliability standards, guidelines, or criteria, the Commission finds that such order would unreasonably impair the continued reliability of electric systems affected by the order.

(c)(1) [Repealed]

(2) No order may be issued under subsection (a) or (b) which requires the transmitting utility subject to the order to transmit, during any period, an amount of electric energy which replaces any amount of electric energy—

(A) required to be provided to such applicant pursuant to a contract during such period, or

(B) currently provided to the applicant by the utility subject to the order pursuant to a rate schedule on file during such period with the Commission: Provided, That nothing in this subparagraph shall prevent an application for an order hereunder to be filed prior to termination of modification of an existing rate schedule: Provided, That such order shall not become effective until termination of such rate schedule or the modification becomes effective.

(3) [Repealed]

(4) [Repealed]

(d)(1) Any transmitting utility ordered under subsection (a) or (b) to provide transmission services may apply to the Commission for an order permitting such transmitting utility to cease providing all, or any portion of, such services. After public notice, notice to each affected State regulatory authority, each affected Federal power marketing agency, each affected transmitting utility, and each affected electric utility, and after an opportunity for an evidentiary hearing, the Commission shall issue an order terminating or modifying the order issued under subsection (a) or (b), if the electric utility providing such transmission services has demonstrated, and the Commission has found, that—

(A) due to changed circumstances, the requirements applicable, under this section and section 212 [16 USCS § 824k], to the issuance of an order under subsection (a) or (b) are no longer met, or

(B) any transmission capacity of the utility providing transmission services under such order which was, at the time such order was issued, in excess of the capacity necessary to serve its own customers is no longer in excess of the capacity necessary for such purposes; or

(C) the ordered transmission services require enlargement of transmission capacity and the transmitting utility subject to the order has failed, after making a good faith effort, to obtain the necessary approvals or property rights under applicable Federal, State, and local laws.

No order shall be issued under this subsection pursuant to a finding under subparagraph (A) unless the Commission finds that such order is in the public interest.

(2) Any order issued under this subsection terminating or modifying an order issued under subsection (a) or (b) shall—

(A) provide for any appropriate compensation, and

(B) provide the affected electric utilities adequate opportunity and time to—

(i) make suitable alternative arrangements for any transmission services terminated or modified, and

(ii) insure that the interests of ratepayers of such utilities are adequately protected.

(3) No order may be issued under this subsection terminating or modifying any order issued under subsection (a) or (b) if the order under subsection (a) or (b) includes terms and conditions agreed upon by the parties which—

(A) fix a period during which transmission services are to be provided under the order under subsection (a) or (b), or

(B) otherwise provide procedures or methods for terminating or modifying such order (including, if appropriate, the return of the transmission capacity when necessary to take into account an increase, after the issuance of such order, in the needs of the transmitting utility subject to such order for transmission capacity).

(e) As used in this section, the term "facilities" means only facilities used for the generation or transmission of electric energy.

(June 10, 1920, c. 285, Part II, § 211, as added Nov. 9, 1978, P. L. 95-617, Title II, § 203, 92 Stat. 3136; June 30, 1980, P. L. 96-294, Title VI, Subtitle D, § 643(a)(3), 94 Stat. 770; Oct. 16, 1986, P. L. 99-495, § 15, 100 Stat. 1257; Oct. 24, 1992, P. L. 102-486, Title VII, Subtitle B, § 721, 106 Stat. 2915.)

Provisions Regarding Certain Orders Requiring Interconnection or Wheeling

Sec. 212.

(a) Rates, charges, terms, and conditions for wholesale transmission services. An order under section 211 [16 USCS § 824j] shall require the transmitting utility subject to the order to provide wholesale transmission services at rates, charges, terms, and conditions which permit the recovery by such utility of all the costs incurred in connection with the transmission services and necessary associated services, including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities. Such rates, charges, terms, and conditions shall promote the economically efficient transmission and generation of electricity and shall be just and reasonable, and not unduly discriminatory or preferential. Rates, charges, terms, and conditions for transmission services provided pursuant to an order under section 211 [16 USCS § 824j] shall ensure that, to the extent practicable, costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for such order and not from a transmitting utility's existing wholesale, retail, and transmission customers.

(b) [Repealed]

(c)(1) Before issuing an order under section 210 [16 USCS § 824 *i*] or subsection (a) or (b) of section 211 [16 USCS § 824*j*(a), (b)], the Commission shall issue a proposed order and set a reasonable time for parties to the proposed interconnection or transmission order to agree to terms and conditions under which such order is to be carried out, including the apportionment of costs between them and the compensation or reimbursement reasonably due to any of them. Such proposed order shall not be reviewable or enforceable in any court. The time set for such parties to agree to such terms and conditions may be shortened if the Commission determines that delay would jeopardize the attainment of the purposes of any proposed order. Any terms and conditions agreed to by the parties shall be subject to the approval of the Commission.

(2)(A) If the parties agree as provided in paragraph (1) within the time set by the Commission and the Commission approves such agreement, the terms and conditions shall be included in the final order. In the case of an order under section 210 [16 USCS § 824i], if the parties fail to agree within the time set by the Commission or if the Commission does not approve any such agreement, the Commission shall prescribe such terms and conditions and include such terms and conditions in the final order.

(B) In the case of any order applied for under section 211 [16 USCS § 824j], if the parties fail to agree within the time set by the Commission, the Commission shall prescribe such terms and conditions in the final order.

(d) If the Commission does not issue any order applied for under section 210 or 211 [16 USCS § 824 *i* or 824j], the Commission shall, by order, deny such application and state the reasons for such denial.

(e) Savings provisions. (1) No provision of section 210, 211, 214 [16 USCS §§ 824i, 824j, 824m], or this section shall be treated as requiring any person to utilize the authority of any such section in lieu of any other authority of law. Except as provided in section 210, 211, 214, [16 USCS §§ 824i, 824j, 824m] or this section, such sections shall not be construed as limiting or impairing any authority of the Commission under any other provision of law.

(2) Sections 210, 211, 213, 214 [16 USCS §§ 824i, 824j, 824l, 824m], and this section, shall not be construed to modify, impair, or supersede the antitrust laws. For purposes of this section, the term "antitrust laws" has the meaning given in subsection (a) of the first sentence of the Clayton Act [15 USCS § 12(a)], except that such term includes section 5 of the Federal Trade Commission Act [15 USCS § 45] to the extent that such section relates to unfair methods of competition.

(f)(1) No order under section 210 or 211 [16 USCS § 824 *i*or 824j] requiring the Tennessee Valley Authority (hereinafter in this subsection referred to as the "TVA") to take any action shall take effect for 60 days following the date of issuance of the order. Within 60 days following the issuance by the Commission of any order under section 210 or of section 211 [16 USCS § 824*i*or 824j] requiring the TVA to enter into any contract for the sale or delivery of power, the Commission may on its own motion initiate, or upon petition of any aggrieved person shall initiate, an evidentiary hearing to determine whether or not such sale or delivery would result in violation of the third sentence of section 15d(a) of the Tennessee Valley Authority Act of 1933 (16 U.S.C. 831n-4) [16 USCS § 831n-4(a)], hereinafter in this subsection referred to as the TVA Act.

(2) Upon initiation of any evidentiary hearing under paragraph (1), the Commission shall give notice thereof to any applicant who applied for and obtained the order from the Commission, to any electric utility or other entity subject to such order, and to the public, and shall promptly make the determination referred to in paragraph (1). Upon initiation of such hearing, the Commission shall stay the effectiveness of the order under section 210 or 211 [16 USCS § 824 *i*or 824j] until whichever of the following dates is applicable—

(A) the date on which there is a final determination (including any judicial review thereof under paragraph (3)) that no such violation would result from such order, or

(B) the date on which a specific authorization of the Congress (within the meaning of the third sentence of section 15d(a) of the TVA Act [16 USCS § 831n-4(a)]) takes effect.

(3) Any determination under paragraph (1) shall be reviewable only in the appropriate court of the United States upon petition filed by any aggrieved person or municipality within 60 days after such determination, and such court shall have jurisdiction to grant appropriate relief. Any applicant who applied for and obtained the order under section 210 or 211 [16 USCS § 824i or 824j], and any electric utility or other entity subject to such order shall have the right to intervene in any such proceeding in such court. Except for review by such court (and any appeal or other review by an appellate court of the United States), no court shall have jurisdiction to consider any action brought by any person to enjoin the carrying out of any order of the Commission under section 210 or section 211 [16 USCS § 824i or 824j] requiring the TVA to take any action on the grounds that such action requires a specific authorization of the Congress pursuant to the third sentence of section 15d(a) of the TVA Act [16 USCS § 831n-4(a)].

(g) Prohibition on orders inconsistent with retail marketing areas. No order may be issued under this Act [16 USCS §§ 791a et seq.] which is inconsistent with any State law which governs the retail marketing areas of electric utilities.

(h) Prohibition on mandatory retail wheeling and sham wholesale transactions. No order issued under this Act [16 USCS §§ 791a et seq.] shall be conditioned upon or require the transmission of electric energy:

(1) directly to an ultimate consumer, or

(2) to, or for the benefit of, an entity if such electric energy would be sold by such entity directly to an ultimate consumer, unless:

(A) such entity is a Federal power marketing agency; the Tennessee Valley Authority; a State or any political subdivision of a State (or an agency, authority, or instrumentality of a State or a political subdivision); a corporation or association that has ever received a loan for the purposes of providing electric service from the Administrator of the Rural Electrification Administration under the Rural Electrification Act of 1936 [7 USCS §§ 901 et seq.]; a person having an obligation arising under State or local law (exclusive of an obligation arising solely from a contract entered into by such person) to provide electric service to the public; or any corporation or association which is wholly owned, directly or indirectly, by any one or more of the foregoing; and

(B) such entity was providing electric service to such ultimate consumer on the date of enactment of this subsection or would utilize transmission or distribution facilities that it owns or controls to deliver all such electric energy to such electric consumer.

Nothing in this subsection shall affect any authority of any State or local government under State law concerning the transmission of electric energy directly to an ultimate consumer.

(i) Laws applicable to Federal Columbia River Transmission System. (1) The Commission shall have authority pursuant to section 210, section 211 [16 USCS §§ 824i, 824j], this section, and section 213 [16 USCS § 824l] to (A) order the Administrator of the Bonneville Power Administration to provide transmission service and (B) establish the terms and conditions of such service. In applying such sections to the Federal Columbia River Transmission System, the Commission shall assure that—

(i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and

(ii) the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 210, section 211 [16 USCS §§ 824i, 824j], this section, or section 213 [16 USCS § 824l], except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

(2) Notwithstanding any other provision of this Act [16 USCS §§ 791a et seq.] with respect to the procedures for the determination of terms and conditions for transmission service—

(A) when the Administrator of the Bonneville Power Administration either (i) in response to a written request for specific transmission service terms and conditions does not offer the requested terms and conditions, or (ii) proposes to establish terms and conditions of general applicability for transmission service on the Federal Columbia River Transmission System, then the Administrator may provide opportunity for a hearing and, in so doing, shall—

(I) give notice in the Federal Register and state in such notice the written explanation of the reasons why the specific terms and conditions for transmission services are not being offered or are being proposed;

(II) adhere to the procedural requirements of paragraphs (1) through (3) of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839(i) (1) through (3)), except that the hearing officer shall, unless the hearing officer becomes unavailable to the agency, make a recommended decision to the Administrator that states the hearing officer's findings and conclusions, and the reasons or basis thereof, on all material issues of fact, law, or discretion presented on the record; and

(III) make a determination, setting forth the reasons for reaching any findings and conclusions which may differ from those of the hearing officer, based on the hearing record, consideration of the hearing officer's recommended decision, section 211 [16 USCS § 824j] and this section, as amended by the Energy Policy Act of 1992, and the provisions of law as preserved in this section; and

(B) if application is made to the Commission under section 211 [16 USCS § 824j] for transmission service under terms and conditions different than those offered by the Administrator, or following the denial of a request for transmission service by the Administrator, and such application is filed within 60 days of the Administrator's final determination and in accordance with Commission procedures, the Commission shall—

(i) in the event the Administrator has conducted a hearing as herein provided for (I) accord parties to the Administrator's hearing the opportunity to offer for the Commission record materials excluded by the Administrator from the hearing record, (II) accord such parties the opportunity to submit for the Commission record comments on appropriate terms and conditions, (III) afford those parties the opportunity for a hearing if and to the extent that the Commission finds the Administrator's hearing record to be inadequate to support a decision by the Commission, and (IV) establish terms and conditions for or deny transmission service based on the Administrator's hearing record, the Commission record, section 211 [16 USCS § 824j] and this section, as amended by the Energy Policy Act of 1992, and the provisions of law as preserved in this section, or

(ii) in the event the Administrator has not conducted a hearing as herein provided for, determine whether to issue an order for transmission service in accordance with section 211 [16 USCS § 824j] and this section, including providing the opportunity for a hearing.

(3) Notwithstanding those provisions of section 313(b) of this Act (16 U.S.C. 825l) which designate the court in which review may be obtained, any party to a proceeding concerning transmission service ught to be furnished by the Administrator of the Bonneville Power Administration seeking review of order issued by the Commission in such proceeding shall obtain a review of such order in the United States Court of Appeals for the Pacific Northwest, as that region is defined by section 3(14) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839a(14)).

(4) To the extent the Administrator of the Bonneville Power Administration cannot be required under section 211 [16 USCS § 824j], as a result of the Administrator's other statutory mandates, either to (A) provide transmission service to an applicant which the Commission would otherwise order, or (B) provide such service under rates, terms, and conditions which the Commission would otherwise require, the applicant shall not be required to provide similar transmission services to the Administrator or to provide such services under similar rates, terms, and conditions.

(5) The Commission shall not issue any order under section 210, section 211 [16 USCS §§ 824i, 824j], this section, or section 213 [16 USCS § 824l] requiring the Administrator of the Bonneville Power Administration to provide transmission service if such an order would impair the Administrator's ability to provide such transmission service to the Administrator's power and transmission customers in the Pacific Northwest, as that region is defined in section 3(14) of the Pacific Northwest Electric Power Planning and Conservation Act (16 U.S.C. 839a(14)), as is needed to assure adequate and reliable service to loads in that region.

(j) Equitability within territory restricted electric systems. With respect to an electric utility which is prohibited by Federal law from being a source of power supply, either directly or through a distribution of its electric energy, outside an area set forth in such law, no order issued under section 211 [16 USCS § 824j] may require such electric utility (or a distributor of such electric utility) to provide transmission services to another entity if the electric energy to be transmitted will be consumed within the area set forth in such Federal law, unless the order is in furtherance of a sale of electric energy to that electric utility: Provided, however, That the foregoing provision shall not apply to any area served at retail by an electric transmission system which was such a distributor on the date of enactment of this subsection and which before October 1, 1991, gave its notice of termination under its power supply contract with such electric utility.

(k) ERCOT utilities. (1) Rates. Any order under section 211 [16 USCS § 824j] requiring provision of transmission services in whole or in part within ERCOT shall provide that any ERCOT utility which is not a public utility and the transmission facilities of which are actually used for such transmission service is entitled to receive compensation based, insofar as practicable and consistent with subsection (a), on the transmission ratemaking methodology used by the Public Utility Commission of Texas.

(2) Definitions. For purposes of this subsection—

(A) the term "ERCOT" means the Electric Reliability Council of Texas; and

(B) the term "ERCOT utility" means a transmitting utility which is a member of ERCOT.

(June 10, 1920, c. 285, Part II, § 212, as added Nov. 9, 1978, P. L. 95-617, Title II, § 204(a), 92 Stat. 3138, Oct. 24, 1992, P. L. 102-486, Title VII, Subtitle B, § 722, 106 Stat. 2916.)

Sec. 213. Information Requirements.

(a) REQUESTS FOR WHOLESALE TRANSMISSION SERVICES.—Whenever any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale makes a good faith request to a transmitting utility to provide wholesale transmission services and requests specific rates and charges, and other terms and conditions, unless the transmitting utility agrees to provide such services at rates, charges, terms and conditions acceptable to such person, the transmitting utility shall, within 60 days of its receipt of the request, or other mutually agreed upon period, provide such person with a detailed written explanation, with specific reference to the facts and circumstances of the request, stating (1) the transmitting utility's basis for the proposed rates, charges, terms, and conditions for such services, and (2) its analysis of any physical or other constraints affecting the provision of such services.

(b) TRANSMISSION CAPACITY AND CONSTRAINTS.—Not later than 1 year after the enactment of this section, the Commission shall promulgate a rule requiring that information be submitted annually to the Commission by transmitting utilities which is adequate to inform potential transmission customers, State regulatory authorities, and the public of potentially available transmission capacity and known constraints.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

[Docket No. RM93-3-000]

POLICY STATEMENT REGARDING
REGIONAL TRANSMISSION GROUPS

POLICY STATEMENT

(Issued July 30, 1993)

AGENCY: Federal Energy Regulatory Commission

ACTION: Policy Statement

SUMMARY: The Federal Energy Regulatory Commission is announcing a general policy of encouraging the development of Regional Transmission Groups (RTGs), and providing guidance regarding the basic components that should be included in RTG agreements filed with the Commission.

DATES: This Policy Statement is effective on July 30, 1993.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in Room 3104, 941 North Capitol Street, N.E., Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing (202) 208-1397. To access CIPS, set your communications software to use 300, 1200, or 2400 bps, full duplex, no parity, 8 data bits, and 1 stop bit. CIPS can also be accessed at 9600 bps by dialing (202) 208-1781. The full text of this rule will be available on CIPS for 30 days from the date of issuance. The complete text on diskette in WordPerfect format may also be purchased from the Commission's copy contractor, LaDorn Systems Corporation, also located in Room 3104, 941 North Capitol Street, N.E., Washington, D.C. 20426.

review the rate charged by such an entity pursuant to a section 211 order under the standards of section 212.

During the final stages of Congress' consideration of the Energy Policy Act, which, as noted above, significantly expanded the Commission's authority to order transmission upon application, representatives of the electric utility industry and other interest groups presented "consensus" Regional Transmission Group (RTG) 4/ legislation for consideration. The consensus proposal would have explicitly required the Commission to "certify" RTGs meeting certain statutory criteria. Included among the criteria were requirements for: broad membership; an obligation for a member transmission-owning utility to wheel power for others, including an obligation to upgrade its system or build new facilities; coordinated regional transmission planning and information sharing; and fair procedures for decision-making and for dispute resolution. Under the proposal, an RTG that met these (and other) standards for Commission certification would have been entitled to have its decisions receive some degree of deference from the Commission (consistent with the FPA). Moreover, the Commission would have been required to afford some degree of deference to the decisions reached through dispute resolution procedures contained in an RTG

4/ The Commission defines an RTG as a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional (and inter-regional) basis.

agreement. The rates charged for transmission by non-public utilities (i.e., entities not otherwise subject to Commission rate jurisdiction) would have had to meet the substantive FPA rate-making standards and would have been subject to suspension and refund as if they were subject to sections 205 and 206 of the FPA. The consensus proposal set forth procedures for the Commission to impose conditions on certification of RTGs, if necessary, and to exercise continuing oversight. Certification was to be denied if all the affected state commissions unanimously objected to certification. The consensus proposal was presented after the conferees had voted on the provisions of the H.R. 776 Conference Report affecting electric power regulation and was not included in the bill. 5/

On November 10, 1992, the Commission issued a Request for Public Comments on the consensus proposal and solicited comments on how the consensus proposal could be adapted into a proposed rulemaking that would address Commission consideration of RTG agreements affecting matters subject to Commission jurisdiction. 6/ We received 100 comments from a wide variety of commenters. Most of the commenters supported the concept of RTGs. However,

5/ See 138 Cong. Rec. S.17,616 and S.17,620-22 (daily ed. Oct. 8, 1992).

6/ 61 FERC ¶ 61,232 (1992).

respective state commissions, find more efficient solutions to region-wide problems. This is critical because the transmission network is highly interconnected; thus, the actions of one party often affect many others.

Many transmission issues (e.g., loop flow) are highly technical. As far as possible, those with technical expertise should resolve such issues directly. RTGs can bring together the technical experts from all interested parties to address technical issues directly. This promises to be more productive than using traditional regulatory approaches, which tend to force parties to polarize their positions, as the primary mechanisms for resolving disputes.

As the generation sector continues to become more competitive, the industry will have many new opportunities to trade power. RTGs can provide a forum in which planning data and other useful information can be compiled and exchanged. 9/ They can also provide a forum for parties to find workable ways to conduct business with each other. RTGs can develop procedures that make transactions efficient for all -- for example, through region-wide trading systems based on electronic bulletin boards.

9/ As the Commission noted in its Notice of Proposed Rulemaking proposing to implement the information-collection requirement in section 213, making more information available will improve efficiency, expedite negotiations, and reduce the number of section 211 applications. New Reporting Requirements Under the Federal Power Act and Changes to Form No. FERC-714, Proposed Rulemaking, IV FERC Stats. & Regs. ¶ 32,493 (1993), 58 FR 17,544 (April 5, 1993).

In short, RTGs promise efficient and expeditious solutions to problems that may stem from expanded transmission access.

B. Recent Developments - Why the time is ripe for Commission action

During the time since the Commission issued the request for public comment on the consensus RTG proposal, there has been considerable activity in various regions of the country concerning the development of RTGs. For example, utilities in New England, California, the upper Midwest, and the Southwest and Northwest regions of the United States have been actively negotiating RTG agreements. 10/ Utilities in other regions also may be considering such agreements. All of these regions differ with regard to generating resource mix, transmission system integration, and existing institutional frameworks. 11/ These factors, among others, can affect the resolution of planning, access, and operational issues important to RTG agreements. Differences in important regional characteristics support the view, expressed by many in written comments on the

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10/ For example, the Southwest Power Pool is considering RTG-like reforms in its Vision Statement of November, 1992. The Western Association for Transmission Systems Coordination and the New England Power Pool are also attempting to form RTGs.

11/ For example, in New England, NEPOOL, a centrally dispatched pool, and in the upper Midwest, MAPP, a non-centrally-dispatched but highly coordinated pool, both already provide for significant sharing of installed and operating reserves of generation resources. Any RTG in these regions may develop as a complement to these power pools.

the Commission's approval of RTG agreements than by the consensual resolutions negotiated by the members.

C. Minimum Components for RTG Agreements

The Commission does not have authority to "certify" RTGs. However, under section 205(c) of the FPA, public utilities must file with the Commission the classifications, practices, and regulations affecting rates and charges for any transmission or sale subject to the Commission's jurisdiction, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services. Thus, a governing agreement or other RTG-related agreement that in any manner affects or relates to jurisdictional transmission rates or services must be approved or accepted by this Commission as just, reasonable, and not unduly discriminatory or preferential under the FPA. 12/ Accordingly, in addition to adopting a general policy of encouraging the development of RTGs, we believe it is also important to provide guidance regarding the basic components that should be included in RTG agreements in order to satisfy FPA requirements.

The experience drawn from the RTGs developing in various areas of the country indicates that there is a need for flexibility in forming these voluntary associations and the agreements that govern them, in order to reflect specific

12/ Any jurisdictional entity seeking to invoke any other basis for jurisdiction over an RTG should set forth its arguments that such other basis exists.

geographic, operational, historical, or other circumstances of the parties. RTG governing agreements may differ substantially both substantively and in terms of the level of detail. For example, an RTG governing agreement may contain only general criteria for determining the rates that will be charged for transmission services, detailed rate formulations, or no price provisions at all. 13/ Likewise, a governing agreement may contain only general criteria regarding terms and conditions of service, or it may specify detailed terms and conditions. We believe it is crucial to RTG development to permit considerable flexibility regarding the formation of RTGs and RTG agreements, particularly at this early stage and in light of the desire to encourage voluntary participation in RTGs. Therefore, parties

13/ The Commission recently issued an inquiry on transmission pricing. Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Notice of Technical Conference and Request for Comments, 64 FERC ¶ 61,109 (1993), 58 FR 36400 (July 7, 1993). Since the FPA does not mandate the use of a particular method in setting rates, the Commission may decide, for example, that in certain circumstances either "postage stamp" rates or distance-sensitive rates would be just and reasonable. The Commission envisions that an RTG may propose a particular pricing method for its region, which the Commission will accept if it finds the method is just, reasonable, and not unduly discriminatory or preferential. Ultimately, however, the Commission must ensure that any rate developed using the method is just, reasonable, and not unduly discriminatory or preferential. If RTG participants are able to reach agreement with regard to specific rates, the RTG agreement should specify the type of rate (e.g., tariff, individual rate schedules, formula), the underlying pricing method, and any necessary cost support.

Component No. 2 provides for adequate consultation and coordination with states. Many commenters, 19/ representing transmission-owning utilities and transmission-dependent entities as well as the states themselves, pointed out the need for involvement of the states in RTGs. We agree that consultation and coordination with the states are critical to the successful implementation of RTGs, especially in view of the fact that states have authority over retail rates which recover transmission costs, integrated resource planning, and siting of transmission facilities. In addition, state involvement in RTGs can allow state agencies to improve communications with utilities and with each other in dealing with transmission concerns, and can facilitate coordinated treatment of siting issues among the states.

It will be our policy to encourage RTGs to involve the states in whatever way is most effective. State participation is important particularly in the formative stages of RTGs. RTGs are encouraged to seek state participation during formation to ensure that the RTG's governing agreement recognizes that actions taken by RTG members under an RTG agreement must be consistent with state and local law.

19/ See, e.g., Comments of National Association of Regulatory Utility Commissioners (joint comments with, among others, Electricity Consumers) at 6-7, The National Regulatory Research Institute at 1, Municipal Electric Utilities of Wisconsin at 2-6, Missouri Public Service Commission at 1-3, and the Large Public Power Council at 18-19.

3. (§ 2.21(c)(1)) An RTG agreement should impose on member transmitting utilities an obligation to provide transmission services for other members, including the obligation to enlarge facilities, on a basis that is consistent with sections 205, 206, 211, 212 and 213 of the FPA. To the extent practicable and known, the RTG agreement should specifiy the terms and conditions under which transmission services will be offered.

Component No. 3 provides for an affirmative obligation to provide transmission services. Many commenters 20/ argued that this is essential to an RTG. An inability to obtain service on reasonable terms and conditions will likely result in filings with the Commission under sections 211 and 212 of the FPA. Section 211 does not place a limit on the meaning of the term "transmission services" and provides that the Commission can order facilities to be enlarged, if needed, to provide requested service. Accordingly, the service obligation of RTG members should extend to all types of transmission services and should include a commitment to expand or upgrade facilities when needed to meet service requirements. Such a commitment by RTG transmitting utilities will assure members that they can obtain transmission services similar to those that the Commission could order upon application under sections 211 and 212. RTGs thus may help to secure the benefits of expanded transmission access, such

20/ See, e.g., Comments of Edison Electric Institute at 3, 16-17, National Independent Energy Producers at 3, Electricity Consumers at 17-19, and Cajun Electric Power Cooperative at 11-12.

users and would be unfair. 22/ An RTG may wish to strive for consensus when dealing with regional grid issues that affect most members. Accordingly, super-majority voting rules may be appropriate in some circumstances. Different regions and organizations may wish to address these issues in their own manner. The Commission believes that RTGs must have substantial flexibility in designing governance procedures to deal with the difficulties that will be encountered. The procedures must be fair and non-discriminatory if an RTG is to meet the objectives discussed above.

6. (§ 2.21(c)(3)) An RTG agreement should include voluntary dispute resolution procedures that provide a fair alternative to resorting in the first instance to section 206 complaints or section 211 proceedings.

Component No. 6 provides for voluntary dispute resolution procedures. The Commission particularly encourages RTGs to develop high quality alternative dispute resolution procedures 23/ for resolving technical and reliability issues. As discussed in detail infra, we encourage proposals under which we would afford substantial deference to outcomes resulting from appropriate alternative dispute resolution (ADR) procedures that are specified in the RTG agreement.

22/ See, e.g., Comments of the Electricity Consumers Resource Council at 21-22, American Public Power Association at 14, Missouri Basin Municipal Power Agency at 26-27, and Northeast Texas Electric Cooperative at 3.

23/ See Comments of the Electric Generation Association at 6, Southern Maryland Electric Cooperative at 11-12.

7. (§ 2.21(c)(4)) An RTG agreement should include an exit provision for RTG members that leave the RTG, specifying the obligations of a departing member.

Component No. 7 provides for an exit provision for RTG members who wish to leave the RTG. If a party has accepted a responsibility under an RTG agreement and then decides to leave the RTG, the obligation of such departing party to comply with its prior commitments should be set forth in the RTG agreement. 24/

D. Other Issues

(1) Adoption of policy statement rather than rule

In the comments on the consensus legislative proposal, EEI and many others, including several TDUs, argued that the Commission should issue a general statement of policy rather than a rule with specific requirements. These commenters argued that the Commission should review RTG agreements on a case-by-case basis as they are filed. Several reliability councils and power pools, as well as others, are concerned that a rule would stifle the developing RTGs by imposing uniform, detailed requirements. A policy statement would allow flexibility for individual RTGs to form in ways that are suited to accommodate unique circumstances in different regions of the country.

Many other commenters, particularly certain TDUs, supported issuance of a rule that would adopt the "consensus proposal;"

24/ For example, under Article II of the Mid-Continent Area Power Pool Agreement, any participant may withdraw by giving four years' written notice.

coordination with states would be one factor influencing the degree of deference the Commission would give to consensual resolutions reached under an RTG.

3. Deference to RTG alternative dispute resolutions

Some commenters argued that the Commission cannot afford any deference to an alternative dispute resolution technique such as arbitration. Several referred to the Commission's lack of authority to "delegate" its authority to private organizations. Others argued that while parties to contracts may agree to arbitration, states must be able to challenge these contracts before the Commission without being hampered by a deference standard.

On the other hand, many commenters argued that alternative dispute resolution proceedings, with some degree of Commission deference, are critical to RTGs. These commenters argued that the Commission has authority to allow parties to a contract to bind themselves to reasonable arbitration procedures with limited Commission review; in other words, a party may contract away its statutory right to Commission review under the normal "just and reasonable" standard.

Another argument raised is that the RTGs' alternative dispute resolution procedures should be used only for technical issues, such as reliability and the adequacy of existing transmission; RTG members could go directly to the Commission with disputes over policy matters (such as cost allocation or the terms and conditions of access).

Whether consensual resolutions are reached by direct negotiation among the parties or by various methods of ADR, 26/ the Commission has the authority and is willing to give appropriate deference to outcomes produced by agreement of the parties. In either case, the Commission must ensure that the resolution is not unjust, unreasonable, or unduly discriminatory or preferential, as required by the FPA, which we are bound to enforce, and that it does not result from the exercise of market power by one party over another.

Voluntary resolution of disputes is consistent with the statutory scheme under the FPA that relies on contracts between the parties in the first instance. 27/ It is also consistent with the Alternative Dispute Resolution Act. 28/ We believe that an RTG agreement that assures that transmission owners cannot exert significant market power or control over non-owners can provide the Commission the assurance it needs to give appropriate deference to voluntary resolutions or resolutions reached as a result of ADR. While the Commission cannot

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26/ ADR can include, but is not limited to, conciliation, facilitation, mediation, early neutral evaluation, fact-finding, mini-trials, and non-binding or binding arbitration. See Administrative Dispute Resolution, Notice of Inquiry, IV FERC Stats. & Regs. ¶ 35,823.

27/ United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332, 337-9 (1956); FPC v. Sierra Pacific Power Co., 350 U.S. 348 (1956).

28/ 5 U.S.C. § 581-593.

does object to the decision, the degree to which the decision was reached under procedures that maximize fairness, and the degree to which the decision is based on a well-developed record.

4. Antitrust concerns

Several commenters expressed concern that RTGs may raise antitrust concerns. Some argued that the Commission cannot guarantee immunity from antitrust proceedings. 32/ While the Commission can provide no guarantees, we agree with other commenters 33/ that RTGs need not violate the antitrust laws. As the Department of Justice pointed out in its comments, 34/ the purpose of RTGs is to encourage competition in generation, not to discourage it, by making transmission more easily available to a wider spectrum of generating entities and by increasing the efficiency of the transmission system. More easily available wheeling should make the market work better and should lead to greater economic efficiency.

In this regard, we note that RTGs are in many ways analogous to power pools, which have been found not to violate the antitrust laws. In Central Iowa Power Cooperative v. FERC,

32/ See Comments of American Public Power Association at 9, Old Dominion Electric Cooperative at 1, Central Power and Light Company at 10.

33/ See, e.g., Comments of Edison Electric Institute at 31-32, Public Generating Pool at 10, Southern California Edison Co. at 5.

34/ DOJ Comments at 1-7.

35/ the court rejected arguments that the Mid-Continent Area Power Pool (MAPP) violated the antitrust laws or policies. The court pointed out that FPA section 202 expresses Congress' view that coordination is in the public interest. It specifically rejected arguments that MAPP constituted price fixing under the Sherman Act because of the pool's service schedules, which set forth rates.

5. Filing Procedures

The Commission expects that most RTGs will contain public utilities. As such, RTG agreements must, at a minimum, be filed under section 205(c) as contracts affecting or relating to transmission services provided by public utilities. We anticipate that most such filings will be made by one or more public utility members, on behalf of all public utilities in the RTG. 36/ If the filing entity believes that the filing will become effective automatically if the Commission does not act on the filing within 60 days, 37/ it should so state in the first paragraph of the cover letter in bold-faced type and should explain the arguments on which that view is based.

35/ 606 F.2d 1156 (D.C. Cir. 1979).

36/ See Western Systems Power Pool, 55 FERC ¶ 61,099, 61,301 (1991), reh'g den'd, 55 FERC ¶ 61,495 (1991), aff'd sub nom. Environmental Action, et al. v. FERC, No. 91-1404 (D.C. Cir. July 2, 1993).

37/ As with all section 205 filings, the Commission intends to notice RTG filings in the Federal Register and to provide an opportunity for comment prior to Commission action on the filing.

sufficient size and contiguity to enable members to provide transmission services in a reliable, efficient, and competitive manner.

(2) An RTG agreement should provide a means of adequate consultation and coordination with relevant state regulatory, siting, and other authorities.

(3) An RTG agreement should include fair and non-discriminatory governance and decisionmaking procedures, including voting procedures.

(c) Other Components.

(1) An RTG agreement should impose on member transmitting utilities an obligation to provide transmission services for other members, including the obligation to enlarge facilities, on a basis that is consistent with sections 205, 206, 211, 212 and 213 of the FPA. To the extent practicable and known, the RTG agreement should specify the terms and conditions under which transmission services will be offered.

(2) An RTG agreement should require, at a minimum, the development of a coordinated transmission plan on a regional basis and the sharing of transmission planning information, with the goal of efficient use, expansion, and coordination of the interconnected electric system on a grid-wide basis. An RTG agreement should provide mechanisms to incorporate the transmission needs of non-members into regional plans. An RTG agreement should include as much detail as possible with regard to operational and planning procedures.

(3) An RTG agreement should include voluntary dispute resolution procedures that provide a fair alternative to resorting in the first instance to section 206 complaints or section 211 proceedings.

(4) An RTG agreement should include an exit provision for RTG members that leave the RTG, specifying the obligations of a departing member.

(d) Filing Procedures. Any proposed RTG agreement that in any manner affects or relates to the transmission of electric energy in interstate commerce by a public utility, or rates or charges for such transmission, must be filed with the Commission. Any public utility member of a proposed RTG may file the RTG agreement with the Commission on behalf of the other public utility members under section 205 of the FPA.

ATTACHMENT C

THE COMMITTEE ON REGIONAL ELECTRIC POWER COOPERATION AND THE WESTERN INTERSTATE ENERGY BOARD WORKSHOP ON REGIONAL TRANSMISSION GROUPS

OCTOBER 20-21, 1993
MONTEREY, CALIFORNIA

by

ROBERT C. ARNOLD
CHAIRPERSON - ITCF
and
EXECUTIVE VICE PRESIDENT
POWER SUPPLY
GPU SERVICE CORP.

HISTORY

- EVOLVED OUT OF A LONG TRADITION OF VOLUNTARY COOPERATION ON LOCAL AND REGIONAL ISSUES.

- 1988 SEVERAL ECAR COMPANIES, AND PJM DEVELOPED A RELIABILITY COORDINATION PLAN TO PROVIDE PROCEDURES FOR REDUCING TRANSACTIONS DURING CONSTRAINED CONDITIONS.

- 1989 VEPCO/APS/PJM DEVELOPED AGREEMENT TO COORDINATE PLANS.

- 1990 ITCF WAS INITIATED. KEY CONSIDERATION WAS PARTICIPATION BY KEY EXECUTIVES THAT COULD EFFECTIVELY AND QUICKLY RESOLVE TRANSMISSION ISSUES.

ITCF MEMBERSHIP (Cont'd.)

PUBLICLY-OWNED UTILITIES

AMERICAN MUNICIPAL POWER-OHIO
INDIANA MUNICIPAL POWER AGENCY
MICHIGAN PUBLIC POWER AGENCY
NEW ENGLAND POWER POOL
NEW YORK POWER POOL:
    NEW YORK POWER AUTHORITY
PIQUA MUNICIPAL POWER SYSTEM
TENNESSEE VALLEY AUTHORITY

NON-UTILITY GENERATORS

THE AES CORPORATION
COGENTRIX
DIAMOND ENERGY, INC.
LG&E POWER SYSTEMS, INC.
U.S. GENERATING COMPANY

COOPERATIVELY-OWNED UTILITIES

ALLEGHENY ELECTRIC COOPERATIVE, INC.
BIG RIVERS ELECTRIC CORP.
EAST KENTUCKY POWER COOPERATIVE
NEW ENGLAND POWER POOL
OLD DOMINION ELECTRIC COOPERATIVE
WABASH VALLEY POWER ASSOCIATION

FOCUS OF FORUM

- VOLUNTARY COOPERATION AND COORDINATION TO MAKE OPTIMUM USE OF TRANSMISSION CAPABILITIES

- RESOLVE POTENTIAL ISSUES IMPARTIALLY AND AS QUICKLY AS POSSIBLE

- COORDINATION OF PLANNING

- DEVELOP ADDITIONAL STANDARDS AND CRITERIA AS NECESSARY TO PROMOTE ABOVE ACTIVITIES

- ASSUMES NERC IS BASIS FOR SETTING MINIMUM RELIABILITY CRITERIA AND FULLY SUPPORTS NERC ROLE IN FURTHER DEVELOPMENT OF SUCH CRITERIA

GAPP

MISSION STATEMENT

EXPLORE THE PRACTICABILITY OF REPLACING THE SINGLE CONTRACT APPROACH WITH A MULTIPLE CONTRACT PATH APPROACH SUCH THAT THE TRANSMISSION SYSTEMS WHICH ARE IMPACTED BY SPECIFIC TRANSACTIONS ARE APPROPRIATELY INVOLVED FROM A CONTRACTING, SCHEDULING AND OPERATIONS PERSPECTIVE.

GAPP

MISSION STATEMENT (CONT'D)

PREPARE A DISCUSSION PAPER FOR THE ITCF WHICH COMPARES THE CURRENT SINGLE CONTRACT PATH APPROACH TO THE IMPLICATIONS OF MULTIPLE CONTRACT PATHS, PARTICULARLY WITH REGARD TO SCHEDULING AND OPERATIONAL CONTROL.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Chapter I

[Docket No. RM93-19-000]

Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act

NOTICE OF TECHNICAL CONFERENCE AND REQUEST FOR COMMENTS

(June 30, 1993)

AGENCY: Federal Energy Regulatory Commission

ACTION: Notice of Technical Conference and Request for Comments

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing this notice to request comments concerning whether it is appropriate to revise the Commission's present pricing policy for transmission services provided by public utilities under the Federal Power Act.

DATES: Written comments must be received by the Commission on or before [insert date that is 60 days after this notice is published in the Federal Register]. Reply comments must be received no later than 30 days after the date that initial comments are due. Notice of the technical conference will be published in the Federal Register at a later date.

ADDRESSES:

Send Comments to:

Office of the Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act	)))))	Docket No. RM93-19-000

NOTICE OF TECHNICAL CONFERENCE AND REQUEST FOR COMMENTS

(June 30, 1993)

I. INTRODUCTION

The Federal Energy Regulatory Commission (Commission) is initiating this proceeding to consider whether it is appropriate to revise the Commission's present pricing policy for transmission services provided by public utilities 1/ under the Federal Power Act (FPA).

Attached to this notice is a discussion paper prepared by the Commission staff setting forth staff's preliminary observations on transmission pricing issues. 2/

Historically, the Commission has permitted public utilities providing firm transmission service over an integrated transmission grid to charge rates reflecting the rolled-in embedded cost of the integrated grid, including the rolled-in

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1/ 16 U.S.C. 824(e).

2/ The staff discussion paper is not being published in the Federal Register, but is available through the Commission's Public Reference Section.

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costs of any new facilities or upgrades which become pa
integrated grid. 3/ The Commission has also historical
designed firm (and non-firm) transmission rates on a "p
stamp" basis. 4/

As described more fully in the staff paper, the Co
has modified its historic, rolled-in embedded cost pric
in the last two years. 5/ Under the revised policy, wh
utility chooses to add new capacity to relieve a transm
constraint, the Commission allows the utility the optio
charging the higher of an embedded cost rate (calculate
include the rolled-in costs of the added facilities) or

3/ In certain circumstances, the Commission has permi
public utilities to charge rates reflecting a shar
savings based on the difference between the seller
incremental generation costs and the buyer's decre
generation costs. See Southern Company Services,
FERC ¶ 61,190 (1986).

4/ Postage stamp rates are based on the theory that,
utility provides transmission service, it uses its
integrated transmission grid to provide the servic
such, postage stamp rates do not vary based on the
transmission provided; in other words, it costs t
amount to move 1 MW of power 10 miles as it does t
100 miles.

5/ Northeast Utilities Service Company (Re Public Ser
Company of New Hampshire), Opinion No. 364-A, 58 F
61,070, reh'g denied, Opinion No. 364-B, 59 FERC ¶
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rehearing, 59 FERC ¶ 61,089 (1992), affirmed in pa
remanded in part sub nom. Northeast Utilities Serv
Company v. FERC, Nos. 92-1165, et al. (1st Cir. Ma
1993) (NU); Pennsylvania Electric Company, 58 FERC
reh'g denied and pricing policy clarified, 60 FERC
reh'g rejected, 60 FERC ¶ 61,244 (1992), appeal pe
92-1408 (D.C. Cir. filed Sept. 11, 1992) (Penelec)

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Section 205 of the FPA. Further, Congress has given the Commission new authority under the Energy Policy Act of 1992 10/ to compel transmission service under certain circumstances if the Commission determines that such transmission is in the public interest and does not unreasonably impair reliability. As a result, transmission rate schedules will be filed pursuant to orders issued under amended FPA section 211. These open access tariffs and rate schedules will provide more opportunities for buyers and sellers to participate in larger geographic markets. These changes underscore the importance of ensuring that our transmission pricing policies promote efficiency, encourage access, and reflect a reasonable allocation of costs.

In these circumstances, the Commission believes that it is now appropriate to examine its present transmission pricing policy to determine if the present policy promotes or discourages efficiency and competition in the wholesale electric market. Accordingly, the Commission invites comments on, and will hold a technical conference on, whether the present pricing policy needs revision, and possible alternative pricing models.

Clearly, any transmission pricing model adopted by the Commission must meet the substantive standards contained in the FPA. Rates for transmission service under section 205 of the FPA must be just and reasonable and not unduly discriminatory or preferential. Rates for transmission service under section 211

10/ Pub. L. No. 102-486, 106 Stat. 2776 (1992).

of the FPA must meet the requirements of section 212(a) of the FPA, as added by the Energy Policy Act. Such rates must: (1) allow the transmitting utility to recover all the costs incurred in connection with the transmission services and necessary associated services including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities; (2) promote the economically efficient transmission and generation of electricity; (3) be just and reasonable, and not unduly discriminatory or preferential; and (4) ensure, to the extent practicable, that costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for service and not from a utility's existing wholesale, retail and transmission customers.

Whether the Commission ultimately decides to retain its present transmission pricing policy, or to adopt a new pricing policy, it will ensure that these substantive legal standards are met. The Commission also invites comments on the scope of the Commission's discretion on transmission pricing under section 212 of the FPA, and on whether the Commission should apply the same pricing under section 205 of the FPA as it applies under section 212.

The Commission invites comments on these issues and on the analyses presented in the attached staff paper, and encourages commenters to present their own suggestions concerning alternative transmission pricing models. The discussion paper is intended to initiate discussion and highlight the scope of this inquiry. It is not intended to limit the dialogue. 11/

In undertaking this inquiry, the Commission recognizes that pricing is only one aspect of ensuring meaningful transmission access and fostering workable competition in the wholesale bulk power market. Other initiatives are currently being considered by the Commission or have already been undertaken. 12/ Certain of these initiatives are a direct result of the Energy Policy Act. Others arise as side issues which will require careful consideration. For example, the Commission will face issues such as what are the appropriate "non-price" terms and conditions of transmission service as well as what constitutes a

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11/ Some of the materials referenced in the discussion paper will be placed in the Commission's public files in this proceeding and will be available for inspection at the Commission's Public Reference Section, Room 3408, 941 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

12/ Earlier this year, the Commission issued a final rule regarding certification of Exempt Wholesale Generators. [Order No. 550 FERC Statutes and Regulations ¶ 30,964; Order No. 550-A, FERC Statutes and Regulations ¶ 30,969 (1993)] On March 30, 1993, the Commission issued a Notice of Proposed Rulemaking dealing with the transmission information requirements of section 213(b) of the FPA. [FERC Statutes and Regulations ¶ 32,493 (1993)]. The Commission has also requested public comment on the issue of Regional Transmission Groups based upon a consensus proposal which was not included in the Energy Policy Act. [61 FERC ¶ 61,232 (1992)].

"good faith" transmission request and reply. The Commission will also face issues regarding the provision of ancillary services, reliability concerns, and determinations of adequate transfer capability. In addition, the Commission recognizes that state regulatory commissions have substantial jurisdiction over transmission facilities. Indeed, transmission facilities are used predominantly to provide service to retail consumers and these facilities are included in retail rate base. Furthermore, most states have siting authority with regard to transmission construction. Consequently, many of the pricing reforms contemplated by this inquiry may implicate state/Federal jurisdictional issues.

We wish to assure commenters that we recognize the spectrum of transmission issues and that we fully intend to address all such issues, whether on a generic basis, or as part of our adjudicative function. Today, we nonetheless have purposefully limited the focus of this inquiry to technical issues related to transmission pricing and certain related legal questions.

II. PUBLIC COMMENT PROCEDURES

The Commission invites all interested persons to submit an original and 14 copies of their written comments. Technical and policy comments on pricing should not exceed 50 pages in length. Comments on legal issues should be submitted in a separate document and should not exceed 25 pages in length. In addition, commenters should submit an executive summary of each set of comments, not to exceed five pages.

The Commission will also permit interested persons to submit reply comments in response to the initial comments filed in this proceeding. Reply comments should not exceed 25 pages in length and should be submitted no later than 30 days after the date that initial comments are due. If reply comments address both technical/policy issues and legal issues, the comments must be divided into two separately labeled sections.

Persons with common interests or views are encouraged to submit joint comments. Commenters should double space their comments, provide a concise description identifying the commenter, and should reference Docket No. RM93-19-000. In addition, commenters should submit a copy of their comments on a 3 1/2 inch diskette in ASCII II format. Initial comments must be filed with the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than [insert date 60 days after publication of this notice in the Federal Register].

All written comments will be placed in the Commission's public files and will be available for inspection at the Commission's Public Reference Section, Room 3408, 941 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

A technical conference to discuss transmission pricing issues will be scheduled on a date to be established after the Commission has had an opportunity to review the comments. The Commission invites interested persons to file requests to

participate in the technical conference. Requests must be in writing and submitted to the Office of the Secretary no later than the date that comments are due. Persons with common interests or views are requested to file joint requests for participation, so that the Commission can accommodate the maximum number of participants. When the Commission issues a subsequent notice specifying the date, time and place for the technical conference, the Commission will identify the agenda for the conference (including format) and the persons who have been selected to participate.

By direction of the Commission.

(S E A L)

Lois D. Cashell

Lois D. Cashell,
Secretary.

NOTE: THIS PAPER WILL NOT BE PUBLISHED IN THE FEDERAL REGISTER

STAFF DISCUSSION PAPER
Transmission Pricing Issues

The Commission is interested in engaging in a broad discussion of transmission pricing reform. This paper sets out major pricing issues that confront the electricity industry. The discussion here reflects the dialogue that has begun within the industry. The Mid-Continent Area Power Pool (MAPP) has recently initiated a re-examination of transmission pricing, including alternatives that would explicitly account for distance in developing transmission rates. The General Agreement on Parallel Paths (GAPP), which is a committee of the Interregional Transmission Coordination Forum, is engaged in a discussion of parallel-path/distance-sensitive pricing concepts. The New England Power Pool has examined transmission pricing issues as part of its Regional Transmission Association discussions. In addition, advanced models of spot transmission pricing, as discussed below, have been developed to the point where serious consideration is warranted. Thus, it is appropriate for the Commission to engage in this inquiry at this time.

Transmission pricing has multiple policy dimensions which will involve important tradeoffs. For example, it is important to provide transmission price signals that accommodate the efficient operation of existing generating plants while also encouraging least cost investment in new plants. At the same time, any pricing reform must also be fair and equitable to existing and new users of the grid. More precise cost measurement is a reasonable goal, but the result should not be overly complex to implement. The Commission must weigh these competing considerations and decide whether reform is appropriate and, if so, how extensive any reform should be. Reform, however, should not be sought for its own sake. Pricing policy changes are appropriate only if they enable the industry to improve its performance at a reasonable cost of implementation. The threshold issue, then, is whether the benefits of changing our existing transmission pricing policy outweigh the costs.

This paper first reviews the Commission's traditional approach to transmission pricing and recent developments that have led to this inquiry. This is followed by a short discussion of the scope of the inquiry in order to focus comments on certain major issues. Included in this discussion is a short list of suggested criteria for evaluating alternative pricing options. The next three sections discuss specific pricing issues that have triggered proposals for reform.

I. BACKGROUND

A. The Commission's Traditional Approach to Transmission Pricing

Historically, the Commission has based its approach to transmission pricing on the rolled-in, average historic costs of the transmitting utility (including those of any affiliates, in the case of holding companies). This precedent was largely developed for requirements

service where the wholesale customer's load is dispersed throughout the utility's service territory and integrated generation and transmission facilities are used. The result has been a "postage stamp" rate, *i.e.*, a unit charge for moving a unit of electricity over the transmitter's grid that does not recognize whether the electricity is transmitted 10 miles or 200 miles. 1/

The Commission has supported the postage stamp method for cost recovery on the grounds that a transmitter's grid is an integrated whole. That is, the Commission has approved single, rolled-in transmission rates because a corporate entity, the transmitting utility, operates its grid in a single, unified way. Such integrated operation complicates the issue of establishing cost responsibility. In addition, the benefits of reliable operation are difficult to separate and quantify in such an integrated system. By averaging system transmission costs and recovering them from all uses of the system, postage stamp rates have the practical virtue of administrative simplicity.

However, postage stamp rates may have important limitations, particularly in providing price signals to transmission users. Such rates may not reflect the cost of scarcity when there is a bottleneck on the grid, the costs of expanding capacity to remove such a bottleneck, or the cost of transmitting power over long distances. Because of the recent enactment of the Energy Policy Act of 1992 (EPAct) and the emerging competition in wholesale power markets, it is now appropriate to reevaluate postage stamp ratemaking.

Utilities transact with one another based on a so-called contract path concept. Under the contract path concept, all parties assume, for pricing purposes, that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. In reality, however, power flows are rarely confined to a designated contract path. Instead, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being wheeled (or transmitted) from one utility to another to travel along multiple parallel paths and divide itself among those paths along the lines of least resistance. This parallel path flow is sometimes called loop flow.

The industry's contract path approach has been incorporated into the Commission's traditional transmission ratemaking. In effect, the industry has adopted and the Commission has accepted a convenient fiction that power travels along a contract path that differs from

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1/ The term "grid" is used in this paper to mean the interconnected network of high-voltage transmission lines. Facilities that provide no system-wide benefit, *e.g.*, radial lines to remote load or facilities connecting generation facilities to the grid, are not considered part of the grid. Under certain limited circumstances, the Commission has allowed transmitting utilities to assign the capital costs of radial lines directly to specific customers. Where appropriate, such costs can be added to the charge for use of the grid. Central Maine Power Company, 54 FERC ¶ 61,206 at 61,611-12 (1991).

the real physical paths. The result is that some utilities whose transmission facilities are used to carry the power in reality, but who are not part of the contract path, may not be adequately compensated unless they seek compensation in a rate case before the Commission. Under Section 205 of the Federal Power Act. if a utility can demonstrate that others are imposing costs on its transmission system, it can file a separate rate to recover the costs imposed. However, this issue is complex and could require a fairly elaborate evidentiary showing.

The current contract path approach to pricing may or may not continue to be appropriate; however, it is clearly an issue which the Commission wishes to explore. In the past, the mismatch between compensation and actual flows was widely accepted, mostly because the industry believed that the overall costs and benefits were roughly balanced--others carried your power as much as you carried their power. In addition, utilities' planning efforts contributed to this balance by sharing the cost of new facilities or by taking turns in building. However, the mismatch has become more difficult to manage or ignore as power flows have become more unidirectional.

In the past 20 years, for example, the divergence between actual and assumed contract path flows has led utilities to install mechanical devices known as phase shifters in both the Eastern and Western Interconnections. A phase shifter is a device that redirects electrical current on an alternating current (AC) transmission grid. In addition, Western utilities experimented with various compensation mechanisms. Insulated from the other interconnections, utilities in the Electric Reliability Council of Texas (ERCOT), under the leadership of the Public Utility Commission of Texas, have been able to fashion wheeling rates that take account of loop flow. ERCOT's ability to deal with actual, as opposed to contracted, power flows has been successful, in part, because of the limited number of utilities involved.

Even with its limitations, the contract path approach to transmission pricing has served the Nation well. It has accommodated substantial amounts of efficient trading in the industry, all at a reasonable administrative cost. Nonetheless, the drawbacks in that approach are creating increasing stress. The expansion of the grid, regional imbalances in available generation resources and the emergence of competitive power markets are helping to create more transactions with benefits and costs that may not balance out among utilities as they have in the past. For example, bundled transactions involving both generation and transmission were prevalent in the past. Such transactions allow the parties to share the benefits associated with the sale of a bundled generation and transmission service. In contrast, a utility providing unbundled transmission service may be fully compensated for its transmission costs, but it does not receive any share of the possibly much larger benefits associated with the power sale. Accordingly, as the trend toward more unbundled

transmission service continues, 2/ greater pressure will be placed on the Commission to adopt pricing policies that identify transmission costs more accurately, to allocate those costs appropriately, to develop rates that convey good price signals to users, and to develop approaches that fairly distribute benefits.

B. Recent Changes to the Traditional Approach

In the last two years, the Commission has attempted to address the industry's changing needs by modifying its transmission pricing policy in some respects. Incremental cost pricing is an example. Under traditional ratemaking, the addition of new, expensive transmission assets can cause average rolled-in rates to go up. If the Commission were to require a utility to provide transmission service (*e.g.*, as a condition for a merger or market-based pricing) for which an expensive upgrade would be needed, native load rates could increase under rolled-in pricing. As a result, native load customers would pay some part of the wheeling costs caused by the third-party service. The Commission has sought to avoid such an outcome.

The Commission recently revised its pricing policy to address this possibility. The revised pricing model was developed in the *NU* merger case 3/ and in the *Penelec* case. 4/ The model is based on a balancing of three principles:

- Hold native load customers harmless

2/ The Commission has accepted unbundled transmission tariffs from a number of utilities, *e.g.*, Utah Power & Light Company, *et al.*, Opinion No. 318, 45 FERC ¶ 61,095 (1988), *order on reh'g*, Opinion No. 318-A, 47 FERC ¶ 61,209 (1989), *order on reh'g*, Opinion No. 318-B, 48 FERC ¶ 61,035 (1989), *aff'd in relevant part sub nom.* Environmental Action Inc. *et al.* v. FERC, 939 F.2nd 1057 (D.C. Cir. 1991); Entergy Services, Inc., 58 FERC ¶ 61,234 (1992), *order on reh'g*, 60 FERC ¶ 61,168 (1992), *appeal pending sub nom.*, Cajun Electric Power Cooperative, Inc. *et al.* v. FERC, Nos. 92-1461, *et al.* (D.C. Cir. filed Sept. 24, 1992).

3/ Northeast Utilities Service Company, Opinion No. 364, 58 FERC ¶ 61,070 (1992) (hereinafter cited as *NU*), *reh'g denied*, Opinion No. 364-B, 59 FERC ¶ 61,042 (1992), *order granting motion to vacate and dismissing request for rehearing*, 59 FERC ¶ 61,089 (1992), *affirmed in part and remanded in part sub nom.* Northeast Utilities Service Company v. FERC, Nos. 92-1165, *et al.* (1st Cir. May 19, 1993).

4/ Pennsylvania Electric Company, 58 FERC ¶ 61,278(1992) (hereinafter cited as *Penelec*), *reh'g denied and pricing policy clarified*, 60 FERC ¶ 61,034 (1992), *reh'g rejected*, 60 FERC ¶ 61,244 (1992), *appeal pending*, No. 92-1408 (D.C. Cir. filed Sept. 11, 1992).

- Provide the lowest reasonable cost-based price to third-party transmission customers

- Prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions.

From these principles, the Commission has adopted two pricing modifications: (1) incremental cost pricing for grid expansion or upgrades that relieve a constraintand (2) opportunity cost pricing for a change in operations that relieves a grid constraint. A change in operations might require the transmitting utility to run uneconomical generation units (called re-dispatching) or to forego off-system sales or purchases (by curtailing scheduled power transfers). Either operational change could free up transmission capacity for use by a third party, without building new capacity.

In implementing these pricing modifications, the Commission has concluded that third-party rates should be high enough to hold native load harmless. As a result, when the grid is expanded, the Commission's current policy allows a utility to charge third party transmission customers the higher of embedded costs (for the system as expanded) *or* incremental expansion costs, but not the sum of the two. When the grid is constrained but the utility chooses to not expand its system, the Commission allows a utility to charge the higher of embedded costs *or* legitimate and verifiable opportunity costs, but not the sum of the two. The opportunity costs, in turn, are capped by incremental expansion costs. These pricing policies are collectively referred to as the "or" option.

Implementing these policies has been controversial. The Commission's "higher of" policy (i.e., the "or" option) has been opposed by some transmission owners who urge the Commission to allow them to charge third party transmission customers the existing embedded cost rate (without the expansion) *and* to specifically assign any additional incremental costs associated with the transaction to the third party requesting service (i.e., the "and" option). This is now known as the "and/or" pricing issue. 5/

The "or" policy is also opposed by some representatives of the parties that the Commission had intended to protect--the native load. Further, some state regulators believe that the "or" pricing policy is not fully compensatory. 6/ At its core, the and/or issue is

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5/ The controversy was discussed in the Congressional Record accompanying the passage of the EPAct. *See, e.g.*, 138 Cong. Rec. H.11412-13 (daily ed. Oct. 5, 1992); 138 Cong. Rec. S.17612-623 (daily ed. Oct 8, 1992).

6/ As an example, see the resolution passed by the Executive Committee of the National Association of Regulatory Utility Commissioners, *Resolution Encouraging State Regulatory Commissions to Consider Reforming Transmission Pricing Policies for*

(continued...)

whether holding native load customers harmless is enough or whether some additional compensation for transmitters is appropriate. In effect, the Commission's benchmark for "hold harmless" is economic neutrality (prevent native load rates from going up), while some transmission owners and state commissions would prefer the benchmark to be some form of fair compensation for the use of existing facilities plus any expansion or opportunity cost. This argument is raised below as part of the discussion of incentives to provide service under the current pricing approach.

The "or" policy has been criticized on other grounds. The "or" policy allows a transmitting utility to charge an embedded cost price, which it will presumably choose to do, when the incremental cost is lower than the embedded cost. This provision is objectionable to some transmission customers who feel that if they must pay incremental cost when it is higher, they should also receive the benefits of paying the incremental cost when it is lower. Assuming that incremental expansion cost is lower than an embedded cost rate, it can be argued in response that such a policy would allow third parties to pay lower rates when service is constrained than when it is not. In addition, it raises questions about equity to native load customers since third-party rates would be lower than native load rates in such circumstances.

II. SCOPE OF THE INQUIRY

Staff believes that, although the Commission's pricing inquiry should be broad ranging, it must be focused in order to be manageable. To help focus the dialogue, Staff particularly encourages comments on the questions raised in this paper. This is not intended to preclude comments on any other transmission pricing issue that commenters believe warrants the Commission's attention. At a minimum, comments should be identified under one of the following three categories:

- Revisions to the Current Pricing Policy
- Reform of Traditional Ratemaking: Firm Service Pricing Issues
- Reform of Traditional Ratemaking: Non-Firm Service Pricing Issues

Within these categories, we ask specific questions that are designated by number later in this paper. Responses to these questions should be identified by reference to the question number.

The scope of this pricing inquiry is limited in two ways. First, this inquiry is limited to wholesale transmission service. Retail wheeling issues will not be addressed. Second,

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6/(...continued)

Retail Electric Services, adopted March 1993. The resolution encouraged state commissions to consider alternative ways of regulating the transmission function as part of retail service in light of the increasing federal role.

Staff recognizes that State regulatory commissions have substantial jurisdiction over transmission facilities. Indeed, transmission facilities are used to provide service to retail consumers and these facilities are included in the retail rate base. Furthermore, most states have siting authority with regard to transmission construction. While this inquiry is not focused on State-Federal issues relating to transmission pricing, commenters are invited to address such issues to the extent that particular reforms are affected by jurisdictional matters.

As a general matter, Staff notes that many of the issues discussed in this paper also are appropriate subjects for discussions within regional transmission groups. 7/ In many instances, regions would not be expected to adopt a uniform national approach in addressing a particular issue, *e.g.*, loop flow.

Staff believes that, to the extent practicable, the criteria to be used to assess alternative transmission pricing options should be explicit. Among the possible criteria that could be used to evaluate any transmission pricing reform are the following:

- Promote efficient use of and investment in the transmission grid and provide appropriate price signals to transmission customers. To the extent practicable, prices should accurately:
  - ► account for transmission constraints
  - ► reflect any prudent costs incurred as a result of transmission service
  - ► reflect the actual power flows of the transmission service
  - ► reflect the distance- and location-sensitive costs of the transmission service
  - ► reflect the prevailing direction of the flow, distinguishing between "with the flow" and "counter flow"
- Address any transition problems arising from the reform
  - ► Balance equity considerations associated with any reform with the potential efficiency improvements
  - ► Mitigate the hardships arising from any reform
- Allow customers an option to have stable prices over time

7/ *See*, Notice of Request for Public Comments on Regional Transmission Group Proposal, Docket No. RM93-3-000, November 1992.

- Be simple to implement and to administer.

QUESTION 1. Comment on these proposed criteria for assessing transmission pricing reform.

Staff recognizes that trade-offs between these objectives are unavoidable. It may not be possible to achieve efficiency, precision and administrative simplicity simultaneously. For example, the Commission will need to assess how complicated the administration of new transmission pricing policies might become in meeting these various criteria. The administrative costs may be higher for some criteria than others. In addition, the economic disruptions accompanying any departure from the status quo must be mitigated, if possible. Any remaining equity concerns then would be weighed against possible efficiencies. Reform is not sought for its own sake, but only as appropriate to support in an equitable manner the industry's evolution towards greater efficiency through competitive power markets.

III. REVISIONS TO THE CURRENT PRICING POLICY

In this section, commenters are invited to suggest changes to the Commission's current transmission pricing model. In Sections IV and V, we suggest possible alternative pricing models.

A. Incentives to Provide Service

As discussed above, some parties believe that the Commission's current implementation of its "or" policy does not provide sufficient incentives for transmission owners to provide service. 8/ They argue that if third parties pay only for the incremental cost of expansion (when this is higher than embedded cost), native load customers will receive no benefit. Those who support the "and" option contend that additional incentives are needed. For example, if third parties were required to pay embedded costs in addition to incremental costs, native load rates would decrease, thereby simultaneously providing a native load benefit and an expansion benefit.

QUESTION 2. Comment on whether the Commission's current "or" pricing policy provides appropriate and sufficient incentives to transmission owners and transmission customers. Explain when benefits to native load customers above those that would be obtained under the "or" policy would be appropriate and when they would not. Further, explain how the Commission could distinguish between appropriate and inappropriate native load benefits in the context of postage stamp ratemaking in which a utility's grid is viewed as an integrated single system. Should the possibility of an

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8/ The incentive for the transmission owner to provide service can be distinguished from the incentive to promote good decision making on the part of transmission customers. The latter incentive is discussed *infra*.

additional financial incentive depend, in part, upon whether the transmission service is offered voluntarily or is mandated? How could the Commission monitor and ensure that "incentives" are not a mechanism for recovering monopoly profits?

The Commission's pricing policy is designed, in part, to hold native load customers harmless. Implicit in that objective is that transmission rates compensate the transmitting utility for all costs incurred in providing the service.

QUESTION 3. Does the Commission's current pricing policy compensate the transmitter for all incurred costs? If not, what elements or cost factors are missing?

As previously discussed, a basic difficulty appears to be that unbundling transmission service will separate its pricing from the benefit sharing associated with power trades. With the exception of a few shared-savings transmission rates, transmission providers receive a cost-based price while power buyers and sellers receive possibly larger trade benefits. This is likely to be the case whether or not the Commission decides to reform its postage stamp ratemaking.

QUESTION 4. How does the unbundling of transmission service affect incentives?

Revenues from transmission service are frequently credited, one way or another, to native load customers by state regulators and the FERC. As a result, if the Commission were to allow higher prices for transmission services, most of the additional revenues would flow through to customers rather than shareholders of the transmitting utility.

QUESTION 5. What incentive to provide service remains if native load receives the benefit of incentives to provide transmission service and shareholders do not? Does the time lag in native load crediting affect this and, if so, how? Should the Commission consider revenue crediting less than 100 percent of third-party transmission revenues in developing rates for wholesale requirements service? How effective would this be given the fact that most "native load" rates are established at the state level?

The Commission has also accepted the concept of opportunity cost pricing, which Staff expects will be developed further in individual cases where specific fact patterns will be important in informing the Commission.

QUESTION 6. Does the Commission's opportunity cost pricing policy as articulated in *NU* and *Penelec* provide adequate incentives to the provider of the wheeling service?

QUESTION 7. Should the provision of third-party wheeling service be entitled to a different rate of return--higher or lower--to reflect the risks inherent in such transactions?

B. Incremental Pricing: Contract Vs. Average Incremental Costs

The Commission currently allows incremental cost pricing for grid expansion needed to fulfill a third-party transmission request. There appear to be two general ways to implement incremental cost pricing. One is to charge separate incremental prices in each transmission contract (contract pricing). The other is to charge a uniform price in all transmission contracts based on an average of current incremental costs (average incremental cost pricing). The Commission has begun to implement the first approach in its current pricing policy, although the full implications of that approach have not yet been raised in a case.

Under the contract pricing approach, a transmission customer pays for particular assets--those system upgrades associated with the customer's service. In exchange for paying for specific investments, the customer presumably would receive certain capacity rights. These rights would be specified in the customer's contract. .Contract pricing would allow a transmission owner to enter into a contract, fixed as to capital recovery and with less risk for other costs, that gives customers substantial price certainty over the term of the contract. This can be especially important for non-traditional power producers that need project financing and may have little room to tolerate fluctuations in future transmission prices. The contract itself might contain provisions for renewal at the end of the contract term depending on the customer's needs and the utility's plans. In addition, the contract might fix certain pricing components, use inflation adjustments for some components, and allow others to be redetermined according to traditional regulatory procedures. The customer could not expect to have rights outside the contract, however. 9/

> QUESTION 8. Under contract pricing, would it be appropriate to develop a separate rate base for each customer? Or should native-load ratepayers remain responsible for a single ratebase with appropriate revenue crediting of all third-party wheeling revenues?

Under the average incremental pricing approach, all customers could be charged some average of the current incremental cost of the grid. This might involve replacement cost pricing or estimates of future expansion costs appropriately averaged over the next few years or some other approach. In contrast to the contract pricing approach, average incremental cost pricing applied uniformly could increase (or decrease) the rates of some third parties because of an expansion caused by others. In addition, some mechanism would have to be developed to ensure that all transmission costs are recovered since this form of incremental cost pricing may not necessarily cover the revenue requirement. Also, the issue of how such

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9/ Under this theory, native-load customers could be considered to have an open-ended, implicit contract with the transmission owner that does not terminate and in which all pricing components are redetermined periodically.

pricing for third-party transmission customers should compare to that for native load customers would have to be addressed.

QUESTION 9. What pricing approaches or rate design policies are needed to ensure an opportunity for recovery of total revenue requirements?

Several comparisons can be drawn between the two approaches, as a general matter. For example, under contract pricing, a customer would not pay for his vintage of incremental cost if the resulting service is not worthwhile to him. This provides a private check using the customer's own perception of value on whether an expensive upgrade is worthwhile. Average incremental cost pricing, by comparison, runs the risk that an expensive upgrade which incremental users would not be willing to finance will be built anyway because its costs are averaged into all third-party rates. In this case, the risk is checked by traditional regulatory oversight. Consequently, over-building risk is dealt with differently under the two approaches.

QUESTION 10. Is there a risk of over-building associated with average incremental cost pricing and, if so, how should such risk be handled?

Average incremental cost pricing for all customers is usually supported by noting that all customers are equally at the margin on any grid. That is, the system needs expansion for one customer only in the context of the aggregate demand of all customers. If any one customer were to reduce its demand, this could accommodate a demand expansion on the part of any other customer, assuming the same facilities would be used by both. Consequently, some would argue, all customers need to face the same incremental price signal at the same time for any particular point on the grid.

Price signaling is different under contract pricing. At any given time, the same price signal is given to all customers that cause expansion, but not otherwise. This succeeds in signaling customers about the financial consequences of future increases in their usage. With respect to decreases in usage, the customer is given a correct price signal to the extent that resale markets work well. That is, if transmission customers can resell existing capacity rights, current customers will be able to reduce their usage. The two approaches, then, depend on different mechanisms to transmit price signals--one uses regulated prices solely, while the other relies on regulation combined with an active resale market.

QUESTION 11. Is it important that all customers face the same incremental price signal and how effective will each approach to pricing be in achieving a single incremental price?

Uniform implementation of incremental cost pricing treats old and new customers the same, *i.e.*, in a non-discriminatory manner, and typically does not require establishing cost

responsibility on a customer-by-customer basis. 10/ In contrast, old and new customers will pay different prices under contract pricing. Whether this difference is due or undue discrimination is a separate question.

QUESTION 12. Would the fact that old and new customers might pay different prices under a contract pricing regime constitute undue price discrimination?

Incremental cost pricing charged uniformly for all customers has the advantage that it would be simpler to administer. Contract pricing requires keeping track of investment vintages and associating these with particular customers. The accounting would become increasingly complex over time.

QUESTION 13. Please comment on whether contract pricing is appropriate for wholesale transmission service and whether it can be administered over the long term at reasonable cost. Are the administrative costs large when compared to the risk of poor investment decisions? Would such pricing give good overall price signals with so many different prices for similar services? In competitive markets, reselling works to eliminate such price differentials. Would reselling be effective in creating a single transmission price signal, say between a specific pair of points on the grid? Is there likely to be a significant resale market for anything other than major corridor service?

QUESTION 14. Should the Commission allow a different rate of return on transmission investment to reflect different riskiness depending on whether a contract pricing or average incremental cost pricing approach is adopted? If so, how would the different riskiness be assessed?

C. Other Issues Relevant to the Current Pricing Policy

Pricing for Grid Expansions. Although the Commission has accepted the concept of incremental cost pricing for transmission service requiring a grid upgrade, it has not specified any particular method for calculating such costs. A method will have to be identified when a utility proposes incremental cost pricing in a specific case.

QUESTION 15. What is the appropriate way to price transmission services that require grid upgrades? Is the approach of computing the revenue requirement with and without the third-party transaction an appropriate incremental pricing approach

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10/ The British National Grid Company charges the same, non-vintaged prices to all users located within the same geographic zones. The Company concluded that it could not fulfill its legal obligation to provide non-discriminatory service if it charged different prices to different users at similar locations with similar characteristics. *See* National Grid Company, *Transmission Use of System Charges Review, Investment Cost Related Pricing--Response to Comments*, Coventry, England, October 30, 1992.

for grid expansion? What would be a reasonable time period to forecast costs and loads for such calculations?

Calculation of Line Losses. A transmission customer may pay for transmission losses either through an in-kind payment (replacement of the energy losses) or as part of the basic transmission rate. The payment typically is based on average line losses, as opposed to marginal line losses which would be higher in most cases. 11/

QUESTION 16. Is the current practice appropriate and, if not, what changes should be made?

Direction of Power Flows. Some transmission transactions may have beneficial effects on transmission systems, *i.e.*, relieve constraints, if they involve new power flows that would go against the prevailing flow.

QUESTION 17. Should transmission pricing take account of the direction of power flows? If so, should a customer be entitled to some form of credit if a particular transaction helps to alleviate a constraint?

Network Service vs. Point-to-Point Service. Commenters are invited to discuss pricing issues pertaining to either point-to-point service or more flexible services such as so-called network service. While there is no universally accepted definition of network service, Staff understands the term to mean transmission service that allows the user to vary its schedule and points of delivery and receipt on the grid without paying an additional charge for each change.

QUESTION 18. Is staff's definition of network service reasonable? Provide recommendations on how network service should be priced.

Ancillary Transmission Services. Commenters are invited to address the pricing of ancillary services, such as voltage support or reactive power service, load following services, scheduling and dispatch service, and operating reserves. Such services are automatically provided as part of bundled power service, such as requirements service or retail service. As more unbundled transmission service is provided, such services can be expected to become increasingly important. Staff recognizes that an important issue for the Commission to deal with is whether the Commission can order the provision of ancillary services and, if so, which ones. This inquiry will focus on the pricing issues and defer the provision question for later consideration.

11/ *See* Northern States Power, 59 FERC ¶ 61,100 (1992), for a discussion of the Commission's current policy on the use of average and marginal line losses in ratemaking.

QUESTION 19. Can commenters suggest other ancillary services, in addition to those listed above? Provide recommendations on how such ancillary services should be priced.

IV. REFORM OF THE CURRENT PRICING POLICY: FIRM SERVICE PRICING ISSUES

It is possible to reform various dimensions of the current model. For example, postage stamp ratemaking could be replaced with distance sensitive pricing. Likewise, the contract path model could be changed to account for parallel flows. Importantly, reform of these dimensions could be combined in various ways. For instance, a postage stamp, parallel path approach is at least theoretically possible. Staff has no preconceived model of pricing. Commenters are invited to suggest any alternatives they believe are appropriate. The following discussion is intended to illustrate the kinds of issues and trade-offs that the Commission is likely to face in evaluating such models.

A. Distance-Sensitive versus Postage Stamp Rates

A postage stamp rate entitles a user to transmit power over any portion of a utility's grid, whether for 10 or 200 miles, for the same rate. Under postage stamps rates, the cost of providing short-distance transmission or transfer service is implicitly averaged with that of long-distance transfer service. This may create a bias in favor of long transfers and against shorter ones.

QUESTION 20. Does the failure of postage-stamp rates to recognize distance create important cross subsidies between long-distance and short-distance transfers?

Several alternatives to postage stamp rates exist that would make the price paid sensitive to the distance involved. One form of distance-related pricing is the MW-mile method, which could be implemented in numerous ways. It could be used to price power flow within a single utility (as in the case of some New Jersey utilities) or among several utilities, as in the ERCOT experience in Texas. 12/

Another way to incorporate distance into transmission rates would be to develop rate zones within a single utility's grid. This might involve dividing the grid into parts for ratemaking purposes. Power moving across each zone would be identified in load flow analyses, which would help to sort out whether the zones and utilities have a parallel relationship (where only a portion of the total power flow burden is physically carried by a particular utility or zone) or a serial relationship (where *all* of the power flow burden is

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12/ An example of the MW-mile method has been proposed by Alfred F. Mistr, Jr. and Everard Munsey, "It's Time for Fundamental Reform of Transmission Pricing," *Public Utility Fortnightly*, July 1, 1992, pp. 13-16.

carried by each of the utilities or zones). Some observers have even suggested facility-by-facility pricing, which would charge users a load-ratio price for each facility used. In the extreme, each facility, *e.g.*, a line or a substation, would effectively become its own rate zone. Further, the concepts of zones and MW-miles could be combined in principle. That is, MW-miles could be used to allocate costs within zones.

> QUESTION 21. How much do transmission costs vary with distance and can such costs be easily quantified? Comment on distance-sensitive pricing in general and on MW-mile methods and zonal methods in particular. Comment on the importance of distance-related rates in providing correct incentives. Would distance-sensitive pricing proposals apply to point-to-point service, or network service, or both?

In addition to incorporating distance correctly, it is also important that transmission prices promote good decisions regarding where to locate new generation facilities. The long-term expected congestion at certain critical grid locations may not be adequately incorporated into distance-sensitive prices. Prices may have to be sensitive to location as well.

> QUESTION 22. Do postage-stamp or distance-sensitive rates provide adequate price signals about the location of new generators? If not, how can transmission prices help promote good location decisions?

B. Contract Path versus Parallel Path Pricing

As discussed in Section I, the contract path approach currently used by the industry may no longer fit its planning and operating needs. Some utilities whose transmission facilities actually carry the power, but who are not part of the contract path, are not likely to be adequately compensated under the contract path approach. This mismatch between compensation and actual flows was widely accepted in the past because of the industry's belief that the overall costs and benefits were roughly balanced and sometimes an explicit effort was made to achieve a balance by sharing the cost of new facilities or by taking turns in building. However, it is staff's impression that the mismatch is growing in magnitude and *ad hoc* efforts to achieve a balancing of costs will no longer work.

Contract path pricing may also create inefficient incentives. For example, it may dilute the incentive of transmission owners to build new transmission assets since others may be able to use the new facilities without charge. Contract path pricing could also complicate coordinated building activity among transmission owners. Regional grid upgrades may need to be made sequentially by several utilities over several years. The utility that first upgrades runs the risk that other utilities may not be able to complete the promised investments that would have provided the expected reciprocal benefits. The other utilities would then get to use the first utility's new capacity for free. No one would want to build first if such a risk were large.

Alternatively, contract path pricing may create an incentive for a utility without significant transmission facilities to build an inefficiently small (low voltage) line in the midst of a high voltage grid in order to create a contract path, assuming that it could meet appropriate reliability criteria. Even with the new line, the utility's power will still flow over the higher voltage lines if, as is likely, there is less resistance on those lines. The result would be that an inefficient investment would be made in order to gain access to a neighboring high voltage grid for free. Such a strategy can benefit the utility if the expected savings in procuring power exceed the investment cost of the needed (token) transmission facilities. In contrast, the more appropriate calculation would examine whether such a low voltage line has any place in the regional transmission plan. Such a line, for example, may make an ineffective contribution to regional reliability or perhaps even detract from reliability if it cannot withstand first contingency power surges when elements of the neighboring high voltage grid fail. 13/

If the industry changes its contract path contracting approach, corresponding pricing changes would be needed. An alternative to contract path ratemaking would be some form of parallel path pricing. Parallel path pricing would compensate transmission owners for use of their grids based on the fraction of the total flow carried by each owner. The fraction of flow carried would be determined by an engineering analysis of the load flow. Each transmission owner's price would recover a contribution to capital.

Another alternative would be to establish capacity rights to the *regional* grid, either on a point-to-point or network-wide basis. Such rights are not systematically defined under the current contract path approach, although the utilities in the Western Systems Coordinating Council have begun to address this issue in their process for rating the simultaneous incremental transfer capability of grid additions. 14/ Payment for the capacity right would constitute the capital contribution under this approach.

QUESTION 23. Assess the benefits and problems of specific alternatives to the contract path approach and the need for such alternatives.

13/ A grid that is built to withstand so-called "first contingencies" is one that can continue to operate within the established safety criteria after it has lost the services of the single, largest and most critical element in the grid, perhaps a critical transmission line or a large generator.

14/ The WSCC process tries to produce line ratings which recognize that individual transmission lines are embedded within a larger network. The rating of any line depends on the operation and configuration of the larger network. Once a line's capacity rating is established through an open "peer review" process, the rating sets limits on the amount of power that can be transmitted over the line.

Parallel path pricing or some other mechanism such as the establishment of capacity rights might neutralize the incentive for transmission owners to not build when they should, and for non-owners to build inefficient facilities. The poor incentives of contract path pricing, however, might be replaced by other poor incentives under parallel path pricing. For instance, parallel path pricing might create an incentive for a utility to build lines at voltage levels much higher than those of its neighbors in order to attract large amounts of parallel flow from neighboring utilities and thus be compensated for them.

> QUESTION 24. Does the current approach to contract-path pricing provide appropriate incentives for transmission construction? Would some other approach, parallel path pricing or better defined capacity rights, provide better incentives for such construction?

This phenomenon apparently exists now even in the absence of parallel flow pricing. Some neighboring utilities trade amounts of power that are smaller than the rating of their direct interconnections and yet a substantial fraction of the flow is carried on higher voltage neighboring systems. These utilities are understandably concerned that parallel path pricing could cause them to pay a third party for transmission service even though their jointly owned interconnection could carry their trade in the absence of the neighbor's lines. This situation needs to be considered in any reform involving parallel path pricing.

> QUESTION 25. Comment on how the Commission should address situations where utilities are required to pay third parties even though their interconnection would appear to be adequate.

One way might be to exempt directly interconnected neighbors from parallel path pricing. As mentioned, another solution might be to establish firm transfer rights that entitle a holder to use the system at no additional charge (except for line loss payments) up to the amount of the firm rights. Usage in excess of the rights could be subject to parallel path pricing. The rights could be established in advance according to ownership shares, demand charge payments, or other financial considerations.

> QUESTION 26. If you would propose to establish capacity rights, comment on the consequences of such exemptions on your proposal.

In questioning the incentives under both pricing regimes--contract and parallel flow--Staff understands that good decisions are frequently made. The industry norm is that high voltage lines do get built now and inappropriate low voltage lines, while possible, are seldom built. Nonetheless, we believe that a pricing regime based on good incentives will improve performance.

> QUESTION 27. Comment on the relative effects of contract path and parallel pricing on the incentives for cost-effective construction of transmission facilities.

Staff believes that parallel path pricing could improve decision making about the use and expansion of the grid. It can more accurately match usage with cost causation by identifying where the power is flowing. In so doing, the parallel portions and serial portions of the flow can be identified. Transmission assets arrayed in a parallel position to carry the power of a particular transaction will share the burden of the flow and accordingly could be allocated an appropriate fraction of the price. Assets arrayed in a serial position will each carry the same power burden and accordingly their costs could be appropriately added. Parallel path pricing could produce dramatic changes from contract path rates. This not only could help to sort out how the power flow burden is shared among parallel path owners, but also could clarify how much of a burden is imposed on serial path owners.

Parallel path pricing would require power flow studies to identify which parallel paths are used in particular transactions. Incorporating load flow information in its pricing practices would be a clear departure for the Commission. The Commission's recent Notice of Proposed Rulemaking on transmission information in Docket RM93-10-000 is relevant here. Staff expects that the information needed to conduct power flow analyses would be assured as a result of this proceeding. Power flow studies would complicate ratemaking considerably. Such a complication may be largely unavoidable, however, since it appears that most proposed pricing reforms would involve such analyses.

> QUESTION 28. Provide suggestions for reforms that would not require power flow studies, as well as suggestions for procedures to resolve technical disputes about such studies.

Staff sees important comparisons between contract pricing of capacity rights, discussed in the previous section, and parallel path pricing. For instance, payment for the capacity rights associated with contract pricing, perhaps through a reservation charge, would be the means for recovering capital costs. Most proposals to create capacity rights have small usage charges that recover only variable costs, such as line losses. In contrast, parallel path pricing recovers a capital cost contribution in rates for usage, not reserved capacity.

> QUESTION 29. Can these two concepts be combined or are they mutually exclusive?

In addition, trading (reselling) is contemplated in most capacity rights proposals. If two parties both own capacity rights between points A and B on the grid, they presumably could compete to resell those rights to a third party. This would be a version of contract path competition. Such competition would appear to be ruled out in a parallel path pricing model since all the utilities on the parallel path would jointly determine which portion of a transaction is carried on each utility's system. Presumably, no utility would charge for or compete to provide service determined to be carried on someone else's system. The utilities on the parallel path are those that jointly possess parallel capacity rights, in effect. Consequently, reselling in a capacity rights model could involve competition among parallel

rights holders to provide service between points of receipt and delivery, while reselling in the parallel path model only would involve returning the capacity to the joint service providers with no competition among them.

QUESTION 30. Is this an important difference between the two models and, if so, which is more appropriate?

C. Equity and Fairness Considerations

The current pricing policy, based on the postage stamp, contract path approach, has prevailed for many years and provides the basis for most trade today. Any change is likely to be disruptive and to affect participants in different ways. Dealing with the equity and fairness ramifications of any pricing reform is important.

QUESTION 31. Comment not only on the efficiency consequences of possible reform, but also on its fairness and equity implications. Provide specific suggestions on how the Commission would manage any transition to a new pricing system, how it would mitigate hardships associated with the transition and how any change would be coordinated among all affected utilities.

QUESTION 32. A possible approach to mitigation would be to apply pricing reform prospectively only, *i.e.*, for new transactions, but not existing ones. If the Commission believed that some version of parallel pricing was appropriate, for example, how should the need for mitigation be weighed against the need to coordinate parallel path pricing among all affected transmitting utilities?

V. REFORM OF THE CURRENT PRICING POLICY: NON-FIRM SERVICE PRICING ISSUES

A. Capital Recovery in Non-Firm Transmission Rates

Non-firm transmission service can be interrupted by the transmitting utility more easily than firm transmission service. A fundamental issue of non-firm transmission pricing is how much of a contribution to fixed costs is appropriate and, further, whether any "demand charge" is appropriate. Such a charge is common practice in the industry today. Despite current practice, many observers believe that recovery of capital costs in non-firm wheeling rates can interfere with short-term efficiency. They argue that the Commission's acceptance of non-firm rates with a capital cost adder discourages economy transactions that could lower generation production costs.

The short-run marginal costs (or variable costs) of transmission consist only of line losses and so-called congestion costs. Congestion costs are the short-term opportunity costs of using constrained facilities, such as the cost of redispatching generation units in order to

free up transmission capacity. 15/ Congestion costs could be addressed by using spot pricing, as discussed *infra*. From this perspective, many economists conclude that non-firm service prices should recover only variable costs. The reasoning is that users of non-firm service should not pay for capacity costs, *per se*, since capacity is not built for them--their service can always be interrupted when the capacity becomes tight.

The Mid-Continent Area Power Pool (MAPP) has used a variant of short-run marginal cost pricing to pay for the transmission service that allows for short-term coordination transactions within the pool for years. Critics of this pricing system argue that non-firm transmission users are "free riders" if the grid has adequate capacity. That is, if grid capacity is unconstrained, congestion costs are zero and non-firm users pay only for line losses. Transmission users can avoid making any contribution to capital by subscribing only to non-firm service. Under current rate base treatment, a utility's native load would not be compensated by such users.

In practice, this problem can be and sometimes is addressed by a requirement that all users make some contribution to capital, perhaps through ownership requirements or capacity deficiency payments or some other contribution mechanism. This approach has been adopted by MAPP, for example. In effect, the transmission owners develop rules that ensure that all users pay a fair share of the capital costs and then pay only for line losses on a transaction-by-transaction basis.

Under one theory, another answer to this dilemma is not to install excess capacity. If capacity is optimal, in this view, it would be occasionally short and so non-firm users would have to pay substantial congestion costs in order to avoid interruption during peak loading periods. Many would then desire firm service. These new firm service users would make capital contributions that adequately compensate native load. In effect, the free rider problem would disappear if firm and non-firm service could be made equally attractive by proper adjustment of capacity, according to this theory.

It is not clear, however, that the optimal level of capacity is one that necessarily makes firm and non-firm service equally attractive over the long run. There are several reasons to believe that some reasonable amount of excess transmission capacity might be optimal. Lumpy investment combined with uneven demand expansion can create long periods of "excess capacity" even if capacity planning is optimal. Some have also argued that, given the relative importance of generation in comparison to transmission, some excess transmission capacity above that needed for reliability purposes should be tolerated in order

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15/ Congestion charges can be viewed as contributions to capital. *See* William W. Hogan, "Electric Transmission: A New Model for Old Principles," *Electricity Journal*, March, 1993.

to have the infrastructure needed to facilitate a competitive generation sector. 16/ In addition, excess transmission capacity would be needed in theory in the absence of very short-term pricing mechanisms that signal the need for end users to curtail during peak transmission loading episodes. The excess in such circumstances would be required to handle short-term needs that cannot be rationed by price. If utilities install excess transmission capacity, for one of these or any other good reason, it could be freely exploited by non-firm users if they paid no capital-contribution charge.

QUESTION 33. Comment on this dilemma: how to give good short-term price signals through non-firm transmission pricing, while avoiding the possibility that non-firm users would make no contribution to capital costs. Is the dilemma important in practice?

B. Spot Pricing for Non-Firm Transmission

Spot transmission pricing refers to very short-term pricing that would reflect hour-to-hour conditions on the grid. Spot prices consist of marginal line losses plus congestion charges. 17/ A spot transmission rate has no demand charge and makes no contribution to capital, except through the highly volatile congestion charge. Such a concept clearly has no place in the Commission's regulation unless the Commission first makes the threshold determination that non-firm demand charges are inappropriate, as discussed above. If the Commission reaches such a determination, Staff is interested in understanding how to implement spot pricing and whether it would improve efficient operation. Note that the issue of how to recover capital costs could be addressed separately, in which case the issues raised in the previous section are relevant.

The theory of spot pricing for transmission is closely related to spot power markets. In the existing literature, *e.g.*, *infra* note 17, well functioning spot markets for power are assumed to exist at multiple locations (buses) around the grid. 18/ These would be multi-lateral trading institutions, perhaps organized like a stock exchange or commodities market. The theory of spot transmission pricing is usually based on the assumption that these

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16/ Charles G. Stalon, "Pricing Transmission Network Services," Presentation to American Bar Association, Denver, Colorado, February 1993, at 8. Generation costs typically constitute about 60 to 75 percent of the price that final customers pay for electricity. Therefore, it is argued that some overinvestment in transmission is desirable if it produces a competitive generation market that lowers generation costs.

17/ For an introductory discussion of spot pricing, *see* K. Kelly, J.S. Henderson, and P. Nagler, *Some Economic Principles for Pricing Wheeled Power*, National Regulatory Research Institute (Columbus, Ohio, August 1987).

18/ A bus is a point on the grid where power is either injected by a generator or taken off by a customer's load. Buses are connected by transmission lines.

dispersed spot markets for power are workably competitive. The literature does not address the question of how well spot transmission pricing would perform if the corresponding spot power markets are not competitive. Regardless, such spot markets for power do not exist today and would represent a substantial departure from the quite active bilateral arrangements for trading power today. Some of the benefits of spot transmission pricing may not be achievable without reform of the institutions for trading short-term power. Accordingly, spot transmission pricing might require more than reform of the Commission's regulation of transmission pricing. The needed institutional reform may be more ambitious than the other pricing reforms discussed in this paper.

QUESTION 34. Comment on the observation that spot transmission pricing might require more than reform of the Commission's regulation of transmission pricing and might involve reform of the underlying market institutions for trading power.

Spot pricing proposals have been developed by several analysts. 19/ Staff is interested in understanding how such pricing could be implemented by the industry to improve coordinated operations.

QUESTION 35. Would spot pricing be intended to improve *ex ante* price signals or be the basis of an *ex post* financial settlements system?

QUESTION 36. Is there a need for spot pricing of inadvertent, unscheduled power flows and, if so, how would this interact with the spot pricing of scheduled transfers?

19/ *See* F.C. Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Norwell MA: Kluwer Academic Publishers, 1988); W.W. Hogan, "Contract Networks for Electric Power Transmission," Working Paper E-90-17, John F. Kennedy School of Government, Harvard University, Cambridge MA, September 1990; M.L. Baughman, S. Siddiqi and J. Zarnikau, "Advanced Pricing in Electrical Systems," University of Texas Working Paper, October 1992; and, M.B. Lively, "Tie-riding Freeloaders--The True Impediment to Transmission Access," *Public Utilities Fortnightly*, December 21, 1989.

AN OVERVIEW OF TRANSMISSION PRICING ISSUES[1]

by

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Presentation to
Western Interstate Energy Board

Monterey, California
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[1] *The analyses and conclusions are those of the author and do not necessarily reflect the views of the Federal Energy Regulatory Commission, any individual Commissioner or any other staff member.*

ATTACHMENT D

Overview of Transmission Pricing

Traditional Pricing -- Postage Stamp

Current Pricing Policy -- "And versus Or" Issue for Incremental Cost

Commission's Inquiry Into Possible Reform

- ***And/Or Issue***
- ***Firm Service: Parallel Path, Distance Sensitivity, and Contract Pricing***
- ***Nonfirm Service: Capacity Charges and Spot Pricing***

Traditional Transmission Pricing

- ***Rolled-In, Average Embedded Cost for Both Firm and Nonfirm Service***
- ***Postage Stamp Ratemaking***
- ***FERC Has Accepted the Industry's Contract Path Fiction***
- ***FERC Compares Non-Postage Stamp Proposals with Postage Stamp Revenues***

Current Transmission Pricing Policy

- *Developed in the NU Merger and Penelec Wheeling Cases*

- *Based on Three Goals for Firm Transmission Service, Consistent with Reliable Service:*

  1. *Hold Native Load Customers Harmless*

  2. *Provide the Lowest Reasonable Cost-Based Third-Party Firm Transmission Rate*

  3. *Prevent Collection of Monopoly Rents by Transmission Owner and Promote Efficient Transmission Decisions*

- *Commission Has Allowed:*

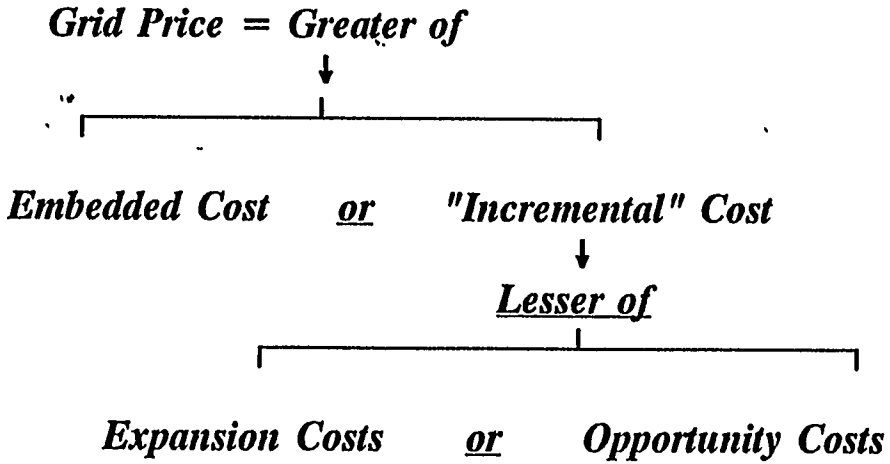
  - *Incremental Cost Pricing when Expansion is Needed*

  - *Opportunity Cost Pricing when there's a Bottleneck but Expansion is not undertaken, Capped by Expansion Costs*

  - *Both Policies Implemented Using a "Higher Of" Formula -- The "Or" Pricing Model*

Current Pricing Policy for Third-Party Firm Transmission

1. *Operating Costs, Plus*
2. *Cost of New Radial Facilities, Plus*
3. *Cost of Grid Facilities*



Incremental Expansion Cost of the Grid

- *The "But For" Test Used To Establish Incremental Cost Responsibility*
- *Potential Outcomes:*
  - *Zero Responsibility -- Trivial case; Price = Embedded Cost*
  - *100 Percent Responsibility -- "Build" case*

    "But For" Test is Simple, No Pro Rata is Needed

    Third Party Pay 100 % of Expansion Costs
  - *Partial Responsibility -- "Build Sooner" Case*
- *Possible Methods:*
  - *Differential Revenue Requirements*
  - *Direct Pro Rata Cost Allocation*

Opportunity Cost Pricing

- *Comparing Opportunity to Embedded Costs (or Expansion Costs)*
  - *Average Opportunity Cost Over the Contract Period*
- *Projected versus Actual Usage*
  - *Upfront Fixed Rate or a Formula Rate that Tracks Actual System Experience?*
  - *Could be Negotiated by the Parties*
  - *Customer Choice Could be Appropriate*
- *Validation*
  - *The Burden of Proof is on the Utility Wishing to Charge Opportunity Costs*

Transmission Pricing Reform Issues

- *Firm Transmission Service*
  - *Parallel-Path Pricing*
  - *Distance Sensitive Rates*
  - *Contract Pricing*

- *Non-Firm Transmission Service*
  - *Non-Firm [Capacity Demand] Charges*
  - *Spot Transmission Pricing*

Parallel-Path Pricing
(How to Deal with Loop Flow)

- *Current Contract Path Pricing is under Increasing Stress*
- *Parallel-Path Pricing would Compensate All (or most) Transmitters*
- *Parallel-Path Pricing would Require Power-Flow Analyses*
- *Power-Flow Analysis could Change the Current And/Or Debate*

Distance-Sensitive Pricing

- *Postage Stamp Rates are Highly Averaged*
- *Postage Stamp Rates Encourage Long Hauls and Discourage Short Hauls*
- *Possible Methods:*
  - *MW-Mile (ITCF)*
  - *Sub-functionalize the Grid (Ala: D.C. Taxi Cabs)*

Contract Pricing

- *Current Rates could Increase Because of New Investment Undertaken for Someone Else?*

- *Contract Pricing could Allow Certain Pricing Components to be Fixed over the Contract*

  - *Advantage: Customer Won't Pay for Expansion that's not Worthwhile to Him*

  - *Disadvantage: Complicated Accounting*

Non-Firm Demand Charges

- *Current Practice Allows a Capacity Charge for Non-Firm Transmission Service (Shared Savings)*

- *Short-Term Efficiency would be Promoted by Charging Only for Line Losses and Constraints*

- *Dilemma: How to Convey Correct Price Signal Without Encouraging Free Riders?*

  - *Economists -- Don't Install Excess Capacity, Then Constraint Pricing Solves the Problem*

  - *Regulator -- Some Excess Capacity is Inevitable Capacity Charge serves as Access Fee*

  - *Others -- Combine Club Pricing for Access with Constraint Pricing for Efficiency*

Spot Transmission Pricing

- *Spot Transmission Pricing is Closely Associated with Spot Power Markets*
  - *Cambridge Theory (Schweppe at MIT, Hogan at Harvard)*
- *Power Market Institutions Matter*
  - *Trading is Currently Bilateral Among Control Areas*
  - *Alternative: Multi-Lateral Trade with a Central Coordinator*
- *Transition to Competition -- Two Steps or One Step?*
  - *Two Steps: Reform Transmission Pricing Now and Market Institutions Later*
  - *One Step: Reform Market Institutions Now Along with Transmission Pricing*
- *RTG Scenario*
  - *RTG establishes pricing appropriate for the region*
  - *Also implements (operations, planning, disputes)*

State Responses to the FERC's

Notice of Inquiry on Transmission Pricing

At the October 20-21 meeting of the Committee on Regional Electric Power Cooperation, states/provinces were asked to send staff a copy of comments they submitted to the FERC on the Commission's transmission pricing inquiry.

The following comments were received:

- Committee on Regional Electric Power Cooperation
- California Energy Commission
- California Public Utilities Commission
- Idaho Public Utilities Commission; and
- Washington State Energy Office

You may want to put these behind Tab D in your *Western RTG Resource Book*.

Responses to the FERC's

Notice of Inquiry on Transmission Pricing

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

INQUIRY CONCERNING THE COMMISSION'S PRICING POLICY FOR TRANSMISSION SERVICES PROVIDED BY PUBLIC UTILITIES UNDER THE FEDERAL POWER ACT	)	DOCKET NO. RM93-19-000

COMMENTS OF THE COMMITTEE ON REGIONAL ELECTRIC POWER COOPERATION

The Committee on Regional Electric Power Cooperation[1] (the Committee), commends the Federal Energy Regulatory Commission (the Commission) for initiating a reexamination of the Commission's pricing policy for transmission services. The Committee recognizes that the information solicited by the Commission in this inquiry is the first necessary step in considering, and potentially adopting, new pricing policies for transmission services.

The Committee offers the following recommendations to the Commission.

1. The Commission should allow and encourage flexibility in national transmission pricing policies. Commission policy should not discourage parties from proposing new pricing policies that promote the efficient planning, construction and operation of the western interconnected system.

2. The timing and substance of a new Commission policy on pricing of transmission services will affect the scope of activities embodied in western Regional Transmission Groups. The Commission should encourage Regional Transmission Groups to propose pricing policies suitable to regional conditions.

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[1] The Committee on Regional Electric Power Cooperation is comprised of the state regulatory commissions, governors' energy agencies and state facility siting agencies in the 11 western states in the Western Systems Coordinating Council region, and the provinces of British Columbia and Alberta.

The Commission has in place policies on the pricing of transmission services based on the traditional contract path concept. The Commission also supports the electric services industry forming Regional Transmission Groups. Over time, however, the access and planning activities of Regional Transmission Groups may uncover weaknesses in current Commission transmission pricing policies that have created barriers to an efficient western electricity system. The Commission should encourage Regional Transmission Groups to propose new transmission pricing arrangements that will promote an efficient western electricity system by giving deference to such proposals.

3. The Commission should clarify the application of its transmission policies and regulations to Native American Nations.

4. The application of the Commission's transmission policies should treat consistently all parties to the western electricity system, including, but not necessarily limited to, Federal Power Marketing Administrations, investor-owned utilities, public power entities, and independent power producers.[2]

[2] The Committee recognizes that the western electricity system includes transmission in Canada and Mexico over which the Commission has no jurisdiction.

FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Concerning the Commission's Pricing Policy For Transmission Services Provided by Public Utilities Under the Federal Power Act	))))	Docket No. RM93-19-000

REQUEST OF THE CALIFORNIA ENERGY COMMISSION
TO PARTICIPATE IN THE TECHNICAL CONFERENCE

The Federal Energy Regulatory Commission (FERC), on June 30, 1993, issued a Notice of Technical Conference and Request for Comments. Therein, the FERC invited interested persons to file a request to participate in a technical conference on transmission pricing issues. The California Energy Commission (CEC) formally requests participation in the technical conference. The CEC is the state energy planning body responsible for transmission planning, an advocate of Regional Transmission Groups, and an active supporter of transmission pricing reform which will enable a competitive electricity market to evolve. The CEC will seek other parties with common interests and views. We ask that the FERC select the Energy Commission as an individual party, or in the alternative, as a specifically named party of a larger group with a representative to be named in the future.

Date: November 4, 1993

RICHARD A. BILAS, Ph.D.
Commissioner and Presiding Member
Intergovernmental Relations Committee

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act	))))	Docket No. RM93-19-000

COMMENTS OF THE CALIFORNIA ENERGY COMMISSION OF THE STATE OF CALIFORNIA

RESPONSE TO FERC REQUEST FOR COMMENTS ON TRANSMISSION PRICING ISSUES

INTRODUCTION

The California Energy Commission (CEC) welcomes the opportunity to respond to the issues raised in the Federal Energy Regulatory Commission's (FERC) June 30, 1993 request for comments on transmission pricing. We would like to congratulate both the FERC and its staff on their excellent and forward-looking work on this issue.

The CEC has recognized the need to reform transmission pricing as a necessary step in promoting the development of competitive electricity markets for a number of years. In a major report on transmission policy, prepared for the California State Legislature in 1991, we recommended opportunity cost pricing as one of a number of measures required to promote non-discriminatory transmission

Transmission access is a key element in the evolution of competitive electricity markets. Embedded costs limited access by third parties because, in many cases, they did not fully compensate a transmission owner for use of its facilities. Providing transmission access when embedded cost rates did not cover costs could result in ratepayers of transmitting utilities subsidizing third-party transmission services (the ratepayer impact issue). Transmission access requests were frequently denied for that reason.

The immediate objective of the FERC's current policy is to resolve the ratepayer impact issue by assuring that a transmitter's native load customers are not adversely affected when wheeling services are made available to third parties. Additional objectives include assuring that the market power of transmitting utilities is mitigated and that transmission users receive the lowest reasonable rates.

The policy designed to achieve these objectives is characterized as the "or" policy. The policy identifies three basic transmission system conditions and allows transmission owners specific pricing options in accordance with these conditions. When the transmission system is unconstrained, the policy allows transmission owners to charge embedded costs. When the system is constrained, but the transmitting utility chooses not to expand its system, transmission owners may charge the higher of embedded or opportunity costs. And finally, when the system is constrained and

run marginal costs) mitigates market power; and as opportunity costs approach incremental costs, they signal the need for transmission expansion.

In addition, the "or" policy provides an excellent framework for moving to a fully market-oriented pricing scheme as conditions change. Allowing transmission owners a choice of embedded costs or marginal costs addresses the immediate goals of reducing ratepayer impacts and mitigating the potential market power of transmission owners. Over the longer term it offers a framework for refining the FERC's treatment of marginal costs and determining how embedded costs should be treated in the future.

While the "or" policy offers a significant improvement over embedded cost pricing, it also causes concerns. For example, some groups believe that transmission customers will be overcharged in cases where embedded costs are greater than a transmitting utility's short-run operating costs, both in unconstrained and constrained situations. This could discourage some efficient transactions. The approach also has equity implications. Since the transmitting utility can always charge the higher of embedded costs or opportunity costs or embedded or incremental costs, third parties may never get the benefit of lower prices.

Other groups argue that neither incremental nor embedded costs will always fully compensate a transmitting utility's ratepayers when capacity expansion is required; again ratepayers would be required

First, when the system is unconstrained, short-run marginal costs would be the appropriate approach to price transmission services; those costs would be based on the transmitter's short-run operating costs--e.g., losses, administrative, and related support costs.

Second, when the transmission system is constrained, but system expansion is not planned, transmission services should be priced at short-run marginal costs, capped at incremental costs. Short-run marginal costs would include the transmitter's short-run operating costs plus any opportunity costs. Opportunity costs could include a number of components. One component would be a charge that would enable the wheeling utility to recover benefits it would forego by providing use of its transmission capacity to a third party. Foregone benefits could be in the form of lost economy energy purchases or lost sales to other utilities. Costs incurred from redispatching the system in order to accommodate third-party wheeling would also be a recoverable opportunity cost.

Opportunity costs, understood in this way, are a form of congestion charge that rations scarce transmission capacity to those most willing to pay. Enabling transmitters to recover foregone benefits through opportunity cost pricing assures that a transmitter's native load customers will not be harmed. Finally, because opportunity costs can increase to incremental costs, they should provide sufficient cost recovery to enable transmitters to add new capacity when the system is fully constrained and additional wheeling is demanded. Incremental costs also provide a reasonable

Marginal Cost Implementation

We realize these proposals could not be implemented immediately but would have to be phased in over a period of time. A major and difficult step would involve phasing out embedded costs as an option in each of the three system conditions--unconstrained, constrained, and where capacity expansion is required--and allowing only marginal cost pricing. Whether this could take place as a single step or in a series of phased steps would depend on a number of factors. We note, however, that the FERC has already approved transmission rates allowing transmitting utilities to charge requestors incremental costs when capacity expansion is required to provide services. This could be an appropriate starting point for phasing out embedded costs.

Phasing out rates based on embedded costs could create inequities and inefficiencies as we make the transition from the present hybrid system to rates based on marginal costs only. One transitional problem could occur if revenue requirements are out of synch with marginal cost transmission pricing policies. For example, undercollection of revenues could occur if revenue requirements, based on embedded costs, were higher than revenues based on marginal costs.

To illustrate: In California, a group of municipal utilities planned a large transmission facility--the California Oregon Transmission Project (COTP)--with the understanding that investor-

Incentives

As noted above, some parties object to the current "or" approach because it may not adequately compensate transmitters when capacity expansion is required or provide adequate incentives for capacity expansion. Others believe it does not provide for the most efficient use of existing transmission capacity.

Our view is that marginal costs already include an incentive and, thus, on both theoretical and practical grounds, additional incentives are probably unnecessary to assure compensation in these situations. Assuring adequate compensation for system expansion depends on how incremental costs are defined. If incremental costs are defined to include all costs related to system expansion--e.g., planning, construction, regulatory and licensing costs, running costs, return on investment, etc., then we would assume costs will be covered. Also, as noted above, incremental costs will include a component allowing transmitters to realize entrepreneurial profits which would compensate them for the risks associated with developing new transmission capacity.

Allowing transmitters to charge the sum of embedded and incremental costs as an incentive (the "and" option) as proposed by some is undesirable because it could result in monopoly rents. Also, allowing an incentive above incremental costs could cause inefficient transmission decisions by encouraging transmission consumers to plan and develop their own alternative transmission

transmission decisions by overpricing or underpricing transmission services.

We recommend that the FERC explore transmission rates based on full marginal costs as an option for pricing transmission services in these proceedings. To implement this approach the FERC should consider phasing out embedded costs as a pricing option and allow full marginal costs--opportunity costs or short-run marginal costs when the system is unconstrained or constrained and incremental or long-run marginal costs when capacity expansion is required.

Date: November 4, 1993

RICHARD A. BILAS, Ph.D.
Commissioner and Presiding Member
Intergovernmental Relations
Committee

CHARLES R. IMBRECHT
Chairman and Member
Intergovernmental Relations
Committee

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Concerning the Commission's Pricing Policy For Transmission Services Provided by Public Utilities Under the Federal Power Act	)	Docket No. RM93-19-000

COMMENTS OF THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

EXECUTIVE SUMMARY

The Federal Energy Regulatory Commission ("Commission") has an historic opportunity to advance transmission pricing to accommodate the needs of a rapidly changing, more competitive wholesale market. The California Public Utilities Commission ("CPUC") strongly supports the Commission's goals of open, nondiscriminatory transmission access. The Commission's new authority to mandate transmission access is crucial to achieving this goal and should help accelerate the development of a workably competitive market in electricity.

It is difficult to imagine, however, how timely or efficient expansion of transmission capacity can occur simply on the basis of traditional utility construction, coupled with occasional requests to the Commission for access orders. There may be several superior models for this expansion, such as development of regional coordination. We join the Commission in supporting regional transmission groups. Another potential model is to give transmission owners an incentive to provide access by letting them earn money on that service, similar to the way the

Commission and the CPUC now promote competition between gas pipeline companies. Failure to create an appropriate mechanism for expansion will forestall the benefits of competition in electric generation.

A competitive generation market requires nondiscriminatory access to a broad variety of transmission services. At the same time, State commissions must ensure that native load customers do not subsidize third-party transmission service. Pricing of transmission services is therefore a key element to both open access and native load protection. Transmission prices should reflect costs of providing service.

The Commission's "or" policy achieves greater efficiency than embedded cost pricing. However, "or" pricing may not always provide sufficient incentives to transmission providers, and may require future modifications to respond to wholesale market developments. If "or" pricing is limited to levels of return which reflect minimal risk, shareholders and regulators will only undertake capacity expansion for a demonstrated need. Providers will not risk building in order to advance development of a market.

The CPUC encourages the Commission to move to capture the efficiency gains available from implementation of marginal cost pricing. The greatest urgency is in improving price signals for new transactions. The CPUC also believes that significant improvement in pricing existing transmission is possible. The CPUC suggests developing a new pricing methodology which uses a combination of costs based on distance and costs based on network usage. To provide a more efficient price signal, transmission

rates should reflect fixed charges for use of the integrated transmission network and variable charges based on distance.

The Commission staff also suggests criteria relating to efficiency, mitigation of hardships and administrative simplicity for changes in pricing policy. In pricing transmission services, the Commission should give higher priority to efficiency, thereby providing price signals to transmission customers which lead to true least-cost wholesale deals. The fact that many potential transmission customers, especially in California, have existing transmission contracts for service should reduce hardships arising from reform. Nonetheless, the Commission should retain flexibility to mitigate undue hardships.

Simplicity of administration, while important, should receive relatively less weight than other criteria. The Commission should try to simplify its oversight of pricing rather than sacrifice efficiency in pricing. Zone of rate freedom for negotiated contract rates could accomplish both objectives of simplicity and efficiency.

Under current state and federal ratemaking practices, utility management has the incentive to increase both the capital investment and services offered to increase earnings for shareholders. The Commission should work together with State commissions to coordinate pricing and incentives. The Technical Conference in this proceeding could be used to develop a mechanism to fairly allocate costs among jurisdictions and to allow utilities to recover all their prudently incurred costs.

At present, retail ratepayers are responsible for bearing the residual responsibility for revenues not obtained from third

parties. For that reason, the CPUC believes that incremental prices should be charged in each transmission contract (contract pricing). Average current incremental cost pricing would require retail ratepayers to bear the contract revenue shortfall.

Since average incremental cost pricing may subsidize transmission requesters, there is a risk of overbuilding. Having similarly situated transmission requestors face the same incremental price signal tends to maximize efficient use of existing facilities. Existing open access tariffs could serve as a benchmark for comparison in Commission review of contract pricing.

Some transmission customers receiving service under existing contracts may be entitled to have the transmission system expanded for less than incremental cost. Contract holders should not be able to exploit the windfall value of that entitlement on behalf of a third party. Society as a whole would then inefficiently undertake construction at less than incremental cost. In general, transmission providers should not be compelled to sell transmission service at regulated rates to a reseller who then resells the service at market rates.

In developing an incremental pricing approach for grid expansion, the CPUC believes that it is appropriate for service requesters to bear the full incremental cost of the transmission investment. As a particular upgrade becomes more fully used, the requester's cost should be reduced. The Commission may also want to consider adopting a simpler test than the classification of facilities as "supportive" or "integral."

Pricing should take account of the direction of power flows. Efficiency would be served by a peak load pricing approach rather than by crediting customers. Such a pricing strategy may help to develop "against the flow" markets.

Network rates may dramatically simplify the marketing of power. Accurate pricing of network service depends upon the nature of the network and any revenue pooling between transmission providers that might occur, as well as other factors.

Respectfully submitted,

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EDWARD W. O'NEILL
MARY F. MCKENZIE

By: /s/ MARY F. MCKENZIE

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November 5, 1993

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all known parties of record in this proceeding by mailing by first-class a copy thereof properly addressed to each party.

Dated at San Francisco, California, this 5th day of November, 1993.

/s/ MARY F. MCKENZIE

Mary F. McKenzie

/afm

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Concerning the Commission's Pricing Policy For Transmission Services Provided by Public Utilities Under the Federal Power Act	)	Docket No. RM93-19-000

COMMENTS OF THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

On June 30, 1993, the Federal Energy Regulatory Commission ("Commission") issued a **Notice of Technical Conference and Request for Comments, Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Docket No. RM93-19-000.** The Public Utilities Commission of the State of California ("CPUC") submits its responses to a number of the questions raised by the inquiry and by Staff's companion transmission pricing discussion paper. The CPUC also provides a separate executive summary of its comments.

I.

INTRODUCTION

Stating that transmission availability and pricing are among its most important policy issues during the upcoming decade, the Commission has requested comments on whether it is appropriate to revise its present pricing policy for transmission services provided by utilities under the Federal Power Act. Historically, the Commission permitted public utilities providing firm transmission service over an integrated transmission grid to

charge embedded cost rates reflecting the rolled-in costs of any new facilities or upgrades which become part of the integrated grid. Also, both firm and non-firm transmission rates have been designed on a "postage stamp" basis.

The Commission's goals of open, nondiscriminatory transmission access are shared by many State public utility regulatory commissions, including the CPUC. Mandatory transmission access is crucial to achieving this goal and will accelerate the development of a workable competitive market in electricity. It is difficult to imagine, however, how timely or efficient expansion of transmission capacity can occur simply on the basis of traditional utility construction, coupled with occasional requests to the Commission for access orders. There may be several superior models for facilitating expansion, including regional coordination and incentives at both the State and national level.

Nondiscriminatory access to transmission is necessary to ensure that California's consumers of energy services receive the full benefits of a competitive electric generation market. At the same time, the CPUC is concerned that native load customers do not subsidize transmission service for third parties. Pricing of transmission services is therefore a key element to both open access and native load protection. The CPUC appreciates this opportunity to comment on the Commission's revised pricing policy as well as offer our suggestions for a new pricing methodology which relies on a combination of costs based on distance and costs based on network usage. These comments also serve as an opportunity to share the CPUC's recent

attempts to foster a system of open, nondiscriminatory transmission access in California.

Our ongoing transmission investigation (I.90-09-050) focused in its first phase on developing a transmission access program for regulated utilities, which would allow the utilities to incorporate transmission costs in bid evaluation in our Final Standard Offer 4 Solicitation. The program considered both integration services, for qualifying facilities bidding to serve the utility in whose service area they are located, and wheeling services within the investor-owned utilities' service area.

Phase II will focus on broader transmission access issues, including access to transmission service for other wholesale purposes. The CPUC anticipates benefits for investor-owned utilities, who will have improved access to generating sources outside of their service territories, and municipal utilities who will have improved access to investor-owned utility facilities. We recognize the overlapping state and federal jurisdiction in this area and emphasize the need for cooperation and coordination among state and federal authorities.

II.

DISCUSSION

Most of the controversy over pricing centers on pricing for firm transmission where the system is constrained. During the last two years, the Commission has modified its rolled-in embedded cost pricing policy on a case-by-case basis. Under the revised policy, termed the "or" pricing policy, when a utility chooses to add new capacity to relieve a transmission constraint,

the Commission allows the utility the option of charging the higher of an embedded cost rate (including the rolled-in costs of the added facilities) or a rate based on the incremental cost of expansion. Where the utility chooses not to add new capacity to relieve a transmission constraint, the Commission allows the utility the option of charging the higher of an embedded cost rate or a rate based on opportunity costs capped at the incremental cost of expansion.

QUESTION 1. **Comment on these proposed criteria for assessing transmission pricing reform.**

The Commission staff has outlined explicit criteria for assessing alternative transmission pricing options to deal with system constraints, including efficiency, precision, equity and administrative simplicity. The CPUC agrees with Commission staff that trade-offs among the objectives are unavoidable as the industry evolves towards greater efficiency in competitive power markets. The CPUC believes that in evaluating transmission pricing proposals, the Commission should give higher priority to promoting efficient use of and investment in the transmission grid, thereby providing appropriate price signals to transmission customers. The Commission can retain flexibility to mitigate undue hardships arising from reform.

The CPUC supports the proposal to offer customers an option which would assure stable prices over time. However, price stability does not necessarily mean a constant price. It may mean a predictable or assured rate of change. Furthermore, the Commission should recognize the risks that a transmission

provider may have assumed in order to provide rate stability. For example, a provider may assume forecast risk in order to offer specific opportunity cost-based rates. This assumption of risk may necessitate a higher rate. The customer could choose between a higher guaranteed rate based on a forecast of opportunity costs, or a lower rate which is subject to the fluctuation of actual opportunity costs.

To the extent the Commission must make trade-offs in setting transmission prices, efficient pricing should be given priority over simplicity of administration. In addition, the wording of this objective implies that pricing proposals should be designed for simplicity of administration. A preferable approach would be to simplify administrative oversight of pricing rather than pricing itself. Developing categorical exemptions would be one way to simplify pricing. Contract rates which are mutually agreeable to two parties and provide revenue below a specified threshold which the Commission finds to be just and reasonable are one example of such an exemption. Another possibility may be to give transmission providers who have filed open access tariffs a zone" of rate freedom (rates that are higher or lower than comparable tariff rates by a certain percent) for negotiation of contract rates.

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QUESTION 2. **Comment on whether the Commission's current "or" pricing policy provides appropriate and sufficient incentives to transmission owners and transmission customers. Explain when benefits to native load customers above those that would be obtained under the "or" policy would be appropriate and when they would not. Further, explain how the Commission could distinguish between appropriate and inappropriate native load benefits in the context of postage stamp ratemaking in which a utility grid is viewed as an integrated single system. Should the possibility of an additional financial incentive depend, in part, upon whether the transmission service is offered voluntarily or is mandated? How could the Commission monitor and ensure that "incentives" are not a mechanism for recovering monopoly profits?**

See response to Question 3.

QUESTION 3. **Does the Commission's current pricing policy compensate the transmitter for all incurred costs? If not, what elements or cost factors are missing?**

The Commission has already attempted to address the industry's changing needs by modifying its transmission pricing policy. Under traditional ratemaking, the addition of new, expensive transmission assets can cause average rolled-in rates to increase. If the Commission required transmission service for which an expensive upgrade is needed, native load rates could increase under rolled-in pricing, violating the principle of efficient pricing that costs should be allocated to the cost-causer. As an alternative to rolled-in embedded cost rates, the Commission has allowed utilities to charge the transmission requestor the incremental costs of the expansion.

The CPUC views the Commission's "or" policy as a more efficient form of pricing than embedded cost pricing and a critical first step in the development of the open transmission

access required for competitive generation. Any beneficial aspects of "or" pricing may be lost, however, if that pricing methodology is out of step with a more competitive market. There are a number of reasons why "or" pricing may not achieve all of the Commission's objectives and may eventually require future modifications.

First, the Commission has dealt with a limited number of transmission pricing requests for something other than embedded cost pricing. The "or" pricing policy has yet to be tested under all possible factual circumstances. For example, the consequences of the "or" policy have not been considered for seasonal service, or other forms of service that might develop. Second, it is difficult to predict how the market for electricity will evolve. The bulk market will increasingly function as other commodity markets do. In the past, transmission lines were sized and built primarily to meet long-term firm demand of native load customers. A competitive bulk power market is likely to expand demand for both firm and interruptible short-term transmission service.

Most importantly, "or" pricing may not provide sufficient financial incentives to expand the transmission grid. Such incentives may be advisable notwithstanding the Commission's new authority to order wheeling. To the extent transmission owners have an opportunity to profit, they will seek to create transmission markets. Demand-driven markets should be encouraged. "Or" pricing that includes a relatively low investment return may not provide a sufficient incentive. At a

minimum, the Commission should consider adjusting return to appropriately reflect risks.

Currently, many transmission owners may simply wait for demand to materialize for a transmission line. Other owners, acting on behalf of shareholders or native load customers, may increase transmission capacity in excess of current customer demand. Transmission owners may assume this risk on behalf of their shareholders, or at the instigation of state regulatory authorities. Regulators may decide that the benefits of increased wholesale competition outweigh the potential costs of excess capacity. However, neither shareholders nor regulators are likely to incur this risk at current levels of return on investment.

Ratepayers currently bear risks of inaccurate forecasts of demand. If the price charged to a third-party transmission customer is based on a demand forecast which turns out to be inaccurate, "or" pricing requires that the ratepayers bear the risk. To remedy this, in setting transmission service rates the utilities should be allowed either to incorporate in their rates a premium charge for price certainty, a premium which increases with the length of the contract term, or to charge a basic tariff which is subject to later additional charges based on subsequent variations in costs (a fluctuating rate tied to some cost index, much like the short-run avoided cost prices in the long term QF purchase agreements.)

The Commission should also recognize that "or" pricing may not lead to least-cost transmission planning. Consider the case where an upgrade is necessary to provide third party service.

Under "or" pricing, the upgrade could be financed on an incremental cost basis. The owner can construct an upgrade that precisely meets a customer's need or can build a larger upgrade, at greater expense, to meet projected demand for future wheeling requests. For example, a transmission line might be constructed to carry two circuits, but string only one circuit. It could be more efficient for the owner to construct the more expensive alternative initially. However, the customer should not be required to pay for that portion of the upgrade it does not use. For this reason, refinement of "or" pricing may be necessary to deal with planning of efficient upgrades.

Where opportunity costs are involved, there are other areas where the incentives provided by "or" pricing may be insufficient for either owners or customers. Refinement of the "or" policy may be desirable to provide a stable rate option.

Rates based on actual opportunity costs may expose transmission requestors to considerable rate fluctuation. At this point in time, opportunity costs associated with use of transmission lines from the Northwest to California are primarily a function of California gas prices and Northwest hydroelectric conditions. Gas is the marginal fuel during most of the time for California utilities. Increased gas prices expand the differential between a utility's marginal cost and Northwest hydroelectricity. The volume and pricing of hydroelectricity is largely based on the quantity of water in the Northwest and environmental constraints. Season-to-season and year-to-year variations in opportunity costs can be dramatic depending on whether conditions are dry, wet or normal. Transmission

requestors may prefer a more stable rate based on a forecast of opportunity costs rather than trying to determine and track the variables of actual opportunity costs. This requires the assumption of some planning risk by the transmission owner, which in turn deserves either a risk premium or approval of various hedging strategies.

The CPUC understands that the application of the Commission's "or" pricing does not require the transmission owner to determine any system benefits to the owner of the incremental addition. For example, some expansions may reduce line losses. Thus, native load customers may receive benefits at no expense if the transmission customer pays the full incremental cost of the expansion.

"Or" pricing may nevertheless present transmission owners with difficult choices. The CPUC understands that ratemaking treatment for incremental additions depends on how the addition is paid for. If the requester pays directly for the incremental addition, but the owner provides the upfront funding, the owner earns a return through its financing of the project, but the investment does not go into ratebase. Where the requester provides the upfront funding including contributions in aid of construction, then the owner might not earn a return. In the situation where the incremental cost is higher than the embedded cost, the "or" policy would set prices at the incremental cost, but the transmission owner would nonetheless prefer charging embedded cost to earn a return for its shareholders.

QUESTION 4. **How does the unbundling of transmission service affect incentives?**

"Or" pricing may give owners the incentive to tie up capacity with power trades and capacity swaps. As the Commission staff explains, in the past, bundled transactions involving both generation and transmission were common. These bundled transactions allowed parties to share benefits associated with the sale of a bundled generation and transmission service. In contrast, a utility providing unbundled transmission service may be fully compensated for its transmission costs, but it does not receive any share of the possibly much larger benefits associated with power and transmission trades. Unbundled transmission will increase pressure on the Commission to adopt pricing policies that identify and allocate transmission costs more accurately. At the same time, at least in the short run until efficient pricing is achieved, reduced benefits associated with providing unbundled transmission service will reduce owners' incentives to provide such service.

In the near term, transmission providers will likely seek to retain the benefits from power and transmission trades. Power exchanges or swaps of transmission usage rights can be more beneficial than sales, even when the provider is convinced that the provider will be able to fully recover opportunity costs. The transmission provider may prefer to swap for use on another line, when the opportunity cost on a provider's line is less than the benefit a provider could derive from use of another transmission line. The comparative benefits of trades over providing unbundled services may give providers a strong

incentive to arrange trades to reduce the capacity available for unbundled sales of transmission.

QUESTION 5. **What incentive to provide service remains if native load receives the benefit of incentives to provide transmission service and shareholders do not? Does the time lag in native load crediting affect this and, if so, how? Should the Commission consider revenue crediting less than 100 percent of third-party transmission revenues in developing rates for wholesale requirements service? How effective would this be given the fact that most "native load" rates are established at the state level?**

The premise to this question is that revenues from transmission service are generally credited by both state regulators and the Commission to native load customers. Commission staff assumes that if the Commission were to allow higher prices for transmission services, most of the additional revenues would flow through to customers rather than shareholders of the transmitting utility.

The electric utility's revenue requirement is determined in part by total utility investment. In determining revenue requirement, the CPUC simply flows through the wholesale revenues which are based on FERC-set wholesale transmission rates.

However, as Commission staff notes, utility shareholders have the opportunity to earn money based on transmission sales. The CPUC generally bases the "revenue credit" on a forecast of transmission sales. When that forecast is adopted as part of a general rate case, utility shareholders can benefit for up to three years if revenues exceed that forecast, giving utilities a clear incentive to increase use of the grid. Expenditures for plant receive a return on investment commensurate with the

market. The more total capital in use, the larger the shareholders' return. Thus, under traditional cost-of-service regulation, utility management has an incentive to increase the total amount of capitalized utility plant. Utility management has the incentive to increase both the capital investment and services offered to increase earnings for shareholders. In crediting ratepayers with transmission service revenues, the utility itself is reimbursed not only for both the capital and operating costs of the plant, but also for any carrying charges for financing construction and for the "opportunity" cost of capital at market rates.

To the extent Commission staff is correct in assuming that incentives may be reduced if benefits are flowed through to retail ratepayers, the Commission should not assume that State commissions will continue current native load crediting practices indefinitely. For example, the CPUC is considering changes to regulating electric utilities. Some of these involve placing greater responsibility on utilities for maximizing use of its asset base. Similarly, a recent NARUC resolution suggested that States not retain bundled retail prices based upon ratebasing of transmission facilities. The Commission should work together with State commissions to coordinate pricing to provide appropriate risk/reward policies which provide utilities with incentives for efficient use of transmission assets, including increased rewards for shareholders. The Commission's consideration of any revenue crediting procedures should be coordinated with State regulatory policies at retail level.

Incentives may provide a way to promote increased transmission access while avoiding conflicts over revenue crediting between federal and state regulators. For example, pricing incentives could be provided contingent on development of coordinated planning or a system of open access, facilitated either by regional transmission groups or open access transmission tariffs, or a combination of both.

Incentives do not always entail direct financial gain to transmission providers. Utilities and their shareholders face threats from customer bypass and new generators. These threats become less viable if utilities succeed in reducing their overall rates. Another incentive is allowing utilities to retain customer base by targeting reduced rates to commercial and industrial customers.

QUESTION 6. **Does the Commission's opportunity cost pricing policy as articulated in NU and Penelec provide adequate incentives to the provider of the wheeling service?**

The CPUC is unclear as to whether the Commission means adequate incentives or adequate compensation. Administrative and evidentiary difficulties may exist in proving opportunity costs, in which case opportunity cost pricing may not provide adequate compensation to the provider of wheeling service.

Adequate financial incentives exist when parties freely undertake the desired transactions. If the transmission owner is <u>required</u> to provide transmission service, the only appropriate question is whether the parties are adequately compensated.

QUESTION 7. **Should the provision of third-party wheeling service be entitled to a different rate of return -- higher or lower -- to reflect the risks inherent in such transactions?**

Generally, the CPUC supports pricing policies which reflect different levels of risk in the rate of return. A different rate of return is only appropriate where differences in risks can be satisfactorily documented. The rate of return should reflect the risks related to third-party wheeling and the type of transaction involved.

The risks of third party wheeling may be greater or less than those of native load service. If a well-financed service user agrees to pay the costs of some upgrade for many years, that transaction is probably less risky than native load service. Shorter terms of service with less security of payment are riskier. The Commission's policies for interstate gas pipelines may be of considerable benefit in assessing the extent of risk.

Transmission providers should be encouraged to undertake more entrepreneurial behavior than has characterized the provision of transmission service in the past. For example, an upgrade with a 30-year life might be built for a user who only requires use of the upgrade for seven years. If there is in fact a risk of underrecovery of capital costs, one possible remedy would be to allow the transmission provider to charge a higher annual rate to the requestor in exchange for assuming the greater risk of unrecovered capital costs. Similarly, a provider may be able to increase transmission route reliability by foregoing some use of transmission lines for its customers in certain

circumstances. A provider must be allowed a commensurate benefit in order to do so. Similarly, a transmission requestor who pays the entire cost of an upgrade should receive benefits commensurate with that commitment.

QUESTION 8. **Under contract pricing, would it be appropriate to develop a separate rate base for each customer? Or should native-load ratepayers remain responsible for a single ratebase with appropriate revenue crediting of all third-party wheeling revenues?**

Commission staff suggests two ways to implement incremental cost pricing. One is to charge separate incremental prices in each transmission contract (contract pricing). The other is to charge a uniform price in all transmission contracts based on an average of current incremental costs (average incremental cost pricing). As explained by Commission staff, under the contract pricing approach a transmission customer pays for those system upgrades associated with the customer's service. In exchange for paying for specific investments, the customer presumably would receive certain capacity rights which would be specified in the customer's contract. Contract pricing allows a transmission owner to enter a contract, fixed as to capital recovery and with less risk for other costs, that gives customers substantial price certainty over the term of the contract. Commission staff believes contract pricing can be important for nontraditional power producers that need project financing and may have little room for uncertainty in future transmission prices.

State commissions are responsible for setting retail rates. NARUC has suggested that States consider revising their pricing policies to move away from bundled rates based on ratebasing

transmission assets. "Revenue crediting" may become irrelevant if retail ratepayers are no longer responsible for bearing the residual responsibility for revenues not obtained from third parties. Whether or not such regulatory change occurs, however, native load ratepayers should not pick up the shortfall in revenue from contracts with third party transmission users.

QUESTION 9. **What pricing approaches or rate design policies are needed to ensure an opportunity for recovery of total revenue requirements?**

Since no one regulatory authority has exclusive responsibility for regulating a utility's opportunity to recover total revenue requirements, there should be coordination between the Commission and the States to establish mechanisms that result in a fair opportunity for the utility to recover all of its prudently incurred costs. Such procedures should include a fair allocation of costs between all jurisdictions -- State/FERC and State/State. The Technical Conference in this docket should consider coordination of federal and state efforts in this area.

QUESTION 10. **Is there a risk of overbuilding associated with average incremental cost pricing and, if so, how should such risk be handled?**

No. There is no risk as long as all customers for whom the upgrade is built are assigned responsibility for the full cost of the facilities. Risk of cost underrecovery can be mitigated both through traditional regulatory oversight (under such traditional doctrines as "prudent investment" or "used and useful"), or the third party customer can make its case to the relevant State siting agency that makes "need for facilities" determinations.

The fact that the Commission may have jurisdiction over pricing wholesale transmission services does not eliminate State jurisdiction over the size, location, and cost of the transmission facilities. The Commission should not average costs among third party users of the facility in question if it would be economically inefficient to do so. On the other hand, the risk of overbuilding risks overburdening the system average (embedded) rate. States may be unwilling to site new facilities if rates are not fully compensatory.

QUESTION 11. **Is it important that all customers face the same incremental price signal and how effective will each approach to pricing be in achieving a single incremental price?**

As a general proposition, the CPUC favors nondiscriminatory pricing policies which treat similarly situated customers similarly. Consistent incremental price signals tend to maximize efficient use of existing facilities. However, customers rarely will be "similarly situated" in terms of location, firmness of service desired, and other factors such as the fact that many transmission customers in California have rights under existing contracts. Moreover, the rights and needs of native load customers (including wholesale requirements consumers) and other uses of transmission facilities may be inherently different. Accordingly, such differences should be taken into account in any revision of the Commission's transmission pricing policies.

Since different prices can be expected in an active market, it is important to minimize potential pricing distortions. Favorably positioned contract holders may be entitled under the

terms of their contracts to have the transmission system expanded for less than incremental cost. Contract holders should not be able to exploit the windfall value of that right on behalf of a third party. Society as a whole would then inefficiently undertake construction at less than incremental cost. Transmission providers should not be compelled to sell transmission service at regulated rates to a reseller who then resells the service at market rates.

The Commission can help to ensure customers face consistent incremental prices for similar services in reviewing new contractual arrangements. Existing open access tariffs could serve as a benchmark for comparison in reviewing contract pricing.

QUESTION 13. **Please comment on whether contract pricing is appropriate for wholesale transmission service and whether it can be administered over the long term at reasonable cost. Are the administrative costs large when compared to the risk of poor investment decisions? Would such pricing give good overall price signals with so many different prices for similar services? In competitive markets, reselling works to eliminate such price differentials. Would reselling be effective in creating a single transmission price signal, say between a specific pair of points on the grid? Is there likely to be a significant resale market for anything other than major corridor service?**

This question suggests there may be a conflict between efficiency and administrative simplicity. As the CPUC's response on criteria recommends, efficiency should take priority over simplicity. The CPUC does not believe, however, that contract pricing will unduly increase administrative costs. As the competitive market emerges, need for the Commission to engage in

detailed scrutiny of contract pricing should decrease, especially if the Commission can compare contract pricing to terms and conditions found in open access transmission tariffs. These tariffs should provide a reasonableness check for individual contracts. The Commission should encourage the filing of open access transmission tariffs.

The Commission staff paper questions whether price signals will provide overall performance adequacy when there are many prices for similar service. The long run direction of wholesale transmission pricing may be a combination of tariff service for most requests, combined with contractual arrangements for customized service. (This model has worked successfully in the telecommunication field, where services are offered on both a tariff and contract basis and provides for a range of firmness and services.)

QUESTION 15. **What is the appropriate way to price transmission services that require grid upgrades? Is the approach of computing the revenue requirement with and without the third-party transaction an appropriate incremental pricing approach for grid expansion? What would be a reasonable time period to forecast costs and loads for such calculations?**

Pricing of incremental transmission will determine the extent of transmission bypass. The CPUC believes that, in some instances, it is appropriate for service requesters to bear the full incremental revenue requirement of the transmission investment. The CPUC essentially adopted this approach for wheeling transactions in its Interim Transmission Program (a pro rata approach was adopted for use for bidders desiring to sell within the same service territory.) The user should receive

commensurate benefits with a full cost allocation approach. As a particular upgrade becomes more fully utilized by subsequent requestors, the revenue requirement attributable to the original service requester should be reduced.

Pricing also depends on the position of the upgrade on the grid. Network additions should be distinguished from radial upgrades. The CPUC assumes that the network is the most divisible level of service. The "or" pricing policy should be applied at the most divisible level of service. For example, the total cost of a radial upgrade of the existing network, to the existing radial delivery point, could be the sum of the incremental revenue requirement for the radial upgrade plus a rental rate for use of the existing network and radial line.

Upgrade costs allocable to the requesting entity include the equipment and other property required for interconnection with the grid. This would include all modifications, upgrades, or relocations of a utility's existing transmission network to the extent these facilities are required for such interconnection. The Commission has recently indicated (see Public Service Electric and Gas Co., order denying intervention and rehearing, 63 FERC ¶ 61,200 (1993)) that such interconnection facilities are the responsibility of the requestor, and are not included in the incremental costs used for the "or" test unless they are "integral" and "supportive" facilities. The Commission may want to consider the following test for integral facilities.

This approach would adopt a bright line test for separate facilities needed for interconnection from facilities needed for delivery of the requested amount of capacity and firmness. For

example, under such an approach, one would segregate facilities needed to get a requestor's 10 firm MW to "the grid", including substation upgrades necessary for the interconnection. All facilities that involve modifications, relocations, or upgrades beyond that point of interconnection would be deemed network upgrades, and deemed necessary for delivery of the 10 MW to some other point.

If the Commission does not adopt a bright line demarcation of "integral" versus "non-integral" facilities, creative selection of "intertie" facilities (requestor pays) from "network" facilities that will be measured against embedded costs in the "or" test, will begin. A simple standard may reduce highly technical, protracted and contentious disputes over whether certain facilities support the system.

QUESTION 16. **Is the current practice appropriate [for calculation of line losses] and, if not, what changes should be made?**

The CPUC believes that the current practice for calculating line losses reflects some significant inaccuracies. Currently, a transmission customer pays for transmission losses either through an in-kind payment (replacement of energy losses) or as part of the basic transmission rate. The payment typically is based on average line losses, as opposed to marginal line losses which would be higher in most cases.

Our understanding is that in some cases losses are based on average peak day losses. Average peak day losses will exceed average losses. The relationship to marginal losses is less clear. In general terms the lower the capacity factor of the

line, the greater the probability that marginal losses will tend to be below average peak day losses.

The CPUC believes movement toward marginal losses is appropriate since in general the CPUC supports marginal cost pricing. However, the difficulty of incorporating marginal losses should not be understated. Losses vary continuously based on the level of line loading and ambient wind and temperature conditions. If the Commission desires a prestated loss rate, numerous simplifying assumptions will be necessary to implement marginal losses. At the same time, average line losses are significantly inaccurate if spread among a whole class of requestors without respect to location, use, or time of day or season.

QUESTION 17. **Should transmission pricing take account of the direction of power flows? If so, should a customer be entitled to some form of credit if a particular transaction helps to alleviate a constraint?**

One important element of a marginal cost pricing strategy is to incorporate the direction of power flows. However, efficiency would be served by a peak load pricing approach rather than by crediting customers. Under this approach, certain transmission rates could be differentiated by time of use and by season. Customers who schedule against the flow could pay a very low usage charge and a zero loss rate. Most costs would be recovered from peak users of the transmission line. Such a pricing strategy may help to develop "against the flow" markets. This could increase the use of transmission, as well as reduce losses.

QUESTION 18. **Is staff's definition of network service reasonable? Provide recommendations on how network service should be priced.**

Commission staff defines network service to mean transmission service that allows the user to vary its schedule and points of delivery and receipt on the grid without paying an additional charge for each change. This definition will evolve over time. It appears to include such services as single point of delivery to multiple points of receipt, multiple points of delivery to multiple points of receipt, and a more limited variety of service that avoids constrained facilities. Some parties may define network service as "anywhere to anywhere" service. While this type of service has a strong theoretical appeal, it appears to pose significant practical difficulties. It may be difficult to analyze in terms of both power flow and cost causation. It is also potentially costly to provide.

In discussing network pricing, it is important to recognize that network service is a different service from the services to which "or" pricing has applied. Network rates could vary based on the predominant direction of flow. Some network services may be provided by a single utility or multiple utilities. For example, California utilities might cooperate to offer a form of California network rate. The pricing innovations mentioned elsewhere in the Commission staff paper can be used to develop the methodology of network service pricing.

Despite these challenges, network service may have the potential to simplify the marketing of power. Consider an independent power producer with a single plant who wishes to sell occasional quantities of excess power. That producer would probably be interested in a single point of delivery with multiple points of receipt. A single type of rate makes calculation of a delivered price to various points much easier than applying rates to each service offered by each transmission provider.

The rate structure for trucking was similarly simplified in California in response to a relaxation of regulation by the CPUC. Previously, the price per truckload was determined based on a laborious determination of the category of freight. Now, the rate for all types of freight is based on a fixed charge plus a rate per mile; a high percentage of freight moves under the simpler rate structure.

Because of the marketing value of this type of rate, the Commission should not be overly prescriptive in how network service should be priced. Appropriate pricing of network service depends on the nature of the network and any revenue pooling between transmission providers which might occur, as well as other factors. A mileage-based rate is reasonably simple and precise, but there may be alternative pricing methodologies which are more likely to lead to regional pricing. For example, instead of using miles of transmission line, mileage might be determined based on the radius of service, i.e., the distance of a straight line from point of delivery to point of receipt.

Variants of postage stamp rates might also be used in pricing. However, the area covered by the postage stamp rate should in many instances, be compressed. For example, instead of a postage stamp rate for all of PG&E's service territory, there might be a rate from anywhere on the main transmission system within the Bakersfield area to anywhere on the main transmission system within the San Francisco Bay area.

The more providers involved in making the service available, the more complex the division of revenue pools could become. Revenue might be divided based on each utility's proportionate share of MW-miles. However, this revenue sharing may not account for variations in investment. Regional transmission groups or existing power pools could contribute to refining pricing schemes.

In order to develop an extensive network offering, rates may not appear to be as cost-based on an individual basis as alternative types of rates. A single rate which applied between 100 and 125 miles of service clearly involves averaging. In reviewing network rates, the Commission should seek to assure that the rates reflect Commission pricing policies on an overall basis. A standard of review that states that each service component must reflect non-network pricing policies with the same level of precision would be unworkably strict.

Network service can be compared to a bundle of rights, which each requestor can pick some combination of, depending on which elements of service it wants to (can afford to) pay for in light of the value of generation delivered. Network service may include regulation and scheduling charges (perhaps as a function

of requested flexibility in delivery) accounting, collection, backup transmission, standby delivery, seasonal variations, time of day variations, loop flow, losses, notice charges varying with how many hours, days, or months ahead of time a schedule change is given, and other services that will develop as the market matures.

QUESTION 20. **Does the failure of postage-stamp rates to recognize distance create important cross-subsidies between long-distance and short-distance transfers?**

Postage stamp rates create cross-subsidies by definition. Whether they are important or not depends on their size and other considerations. In a recent Resolution, the NARUC agreed that FERC should consider establishing transmission prices which reflect distance and location-sensitive costs of service.

Postage stamp rates not only create pricing distortions, but may also result in uneconomic bypass. Geographically larger systems have greater potential for cross-subsidies and uneconomic bypass.

Although it is difficult to assess how important these cross-subsidies are, the CPUC's experience suggests that postage stamp ratemaking do create important cross-subsidies. For example, some of California's long distance interstate network includes the Pacific Intertie. PG&E had proposed postage stamp cost attribution in ranking certain independent producer bids in transmitting that power anywhere between the Oregon border and receipt into the Southern California Edison system. Many producers are located in the extreme southern end of PG&E's system, close to the Edison point of receipt. Those producers

alleged that they would build their own lines to the point of interconnection and simply interconnect outside PG&E's system. In response, PG&E developed an unbundled rate for use of the Midway substation that appears to have addressed those concerns. Even though this particular problem was corrected, other subsidies may continue.

As the CPUC indicates in response to Q18, variants of postage stamp rates can play a useful role. While broad based postage stamp rates create substantial cross subsidies, more area-compressed postage stamp rates should create relatively minor subsidies.

QUESTION 21. **How much do transmission costs vary with distance and can such costs be easily quantified? Comment on distance-sensitive pricing in general and on MW-mile methods and zonal methods in particular. Comment on the importance of distance-related rates in providing correct incentives. Would distance-sensitive pricing proposals apply to point-to-point service, or network service, or both?**

The CPUC suggests developing a new pricing methodology which uses a combination of costs based on distance and costs based on network usage. The CPUC believes that distance should play a greater role in wholesale transmission pricing, particularly in the Western region. Over one hundred thousand circuit miles of transmission lines are in the Western Systems Coordinating Council. More than 50,000 of those miles are comprised of lines with capacities greater than 230 kV. Our conclusion is that better cost-based rates will be derived from a combination of distance based rates plus a network usage charge, rather than distance or postage stamp ratemaking alone.

Postage stamp rates are based on the theory that the utility's grid should be viewed as an integrated single system. Postage stamp based rates are relatively simply to calculate and administer.

The Western grid is increasingly integrated. The trend toward greater integration is likely to continue as efficiency results. Considerable investment in phase shifters and various kinds of protective equipment has been necessary to maintain the integrity of the interconnected grid.

Distance is also an important cost factor. The costs to transport power from the California border to Redding are not the same as the costs to transport power from the border to Midway (several hundred miles south). Yet, postage stamp rates charge the same amount for each service. To provide a more efficient price signal, transmission rates should reflect both costs integral to the integrated transmission network and those which are a function of distance.

As a first step, the Commission should institute a technical study to develop rules for a combined pricing methodology. The study should be given a time limit of six to eight months. One possible area for study would be to compare various transmission systems, with a goal of developing statistical coefficients related to distance and network characteristics. Another alternative would be to classify various units of equipment as distance related, network related, or some combination of the two. Study results could serve as a basis for utilities to file rates which better reflect cost.

Upon study completion, the Commission could convene a technical conference to determine whether the study is a sufficient basis for transmission rates. Options for selection of a research group include Commission staff, independent consultants or various industry groups. Alternatively, various regions could conduct separate studies, since there is a good chance that cost relationships differ by regional market.

QUESTION 28. **Provide suggestions for reforms that would not require power flow studies, as well as suggestions for procedures to resolve technical disputes about such studies.**

Regional transmission groups (RTGs) could play a prominent role in resolution of technical disputes. The regional perspective and broad industry focus of RTGs should make these organizations effective in resolving such disputes. A fair and expeditious alternative dispute resolution (ADR) procedure may be the best forum for resolving technical disputes when upgrades are necessary. In a fast-paced competitive market, access delayed may be access denied. While the Commission's good faith transmission response and request guidelines provide for a timely 60 day response, there may be substantial delays when an upgrade is necessary. Also, 60 days is far too long to accommodate transmission requests for short-term transactions.

QUESTION 31. **Comment not only on the efficiency consequences of possible reform, but also on its fairness and equity implications. Provide specific suggestions on how the Commission would manage any transition to a new pricing system, how it would mitigate hardships associated with the transition and how any change would be coordinated among all affected utilities.**

See response to Question 32.

QUESTION 32. **A possible approach to mitigation would be to apply pricing reform prospectively only, i.e., for new transactions, but not existing ones. If the Commission believed that some version of parallel pricing was appropriate, for example, how should the need for mitigation be weighed against the need to coordinate parallel path pricing among all affected transmitting utilities?**

There are several parallels between the situation faced by the Commission for transmission and that faced by the CPUC in pricing services for retail customers. In the early eighties the CPUC started to move from embedded cost to marginal cost pricing. The CPUC phased in marginal costs over a period of time. This phase-in appears to have successfully mitigated many transition problems. The CPUC encourages the Commission to move to capture the efficiency gains available from implementation of marginal cost pricing.

Many transmission customers have long-term contracts which shield those customers from changes in pricing policy. This has the advantage of mitigating hardships for many customers. However, it also has the concomitant disadvantage of having different customers faced different prices. Consequently, there may be opportunities for arbitraging such artificial price advantages. Those opportunities may complicate the competitive landscape.

The greatest urgency is in improving price signals at the margin, i.e. for new transactions. However, prospective application of pricing reform as currently proposed by Commission Staff tips the balance too far in favor of mitigation versus

efficiency. There is little need for mitigation for new transactions, since transmission users do not have a legitimate expectation that prices will remain substantially as they are. Transmission users (and providers) may well have made investments based on an expectation of stable prices. Consequently, limiting the rate of change of those prices is a reasonable mitigation strategy. If there are relative few existing transmission customers, it may be possible to protect each customer individually. For example, the overall cost of existing transmission service might be limited to some certain percent annual increase. Mitigation measures should apply to individual customers rather than rates in general. This will help prevent unnecessary mitigation. For example, a customer who faces much higher rates for one service may also benefit from much lower rates on another existing service.

III.

CONCLUSION

The CPUC welcomes the opportunity to enter a dialogue with the Commission and other states on transmission pricing policy questions. Depending on the availability of travel funds, the CPUC would like to reserve an opportunity to participate in the

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upcoming technical conference(s). In particular, we would like to address any areas of our comments that the Commission would like to discuss further.

Respectfully submitted,

PETER ARTH JR.
EDWARD W. O'NEILL
MARY F. MCKENZIE

By: /s/ MARY F. MCKENZIE

Mary F. McKenzie

Attorneys for the Public Utilities Commission of the State of California

505 Van Ness Avenue
San Francisco, CA 94102
(415) 703-2760

November 5, 1993

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all known parties of record in this proceeding by mailing by first-class a copy thereof properly addressed to each party.

Dated at San Francisco, California, this 5th day of November, 1993.

/s/ MARY F. MCKENZIE

Mary F. McKenzie

/afm

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

INQUIRY CONCERNING THE COMMISSION'S PRICING POLICY FOR TRANSMISSION SERVICES PROVIDED BY PUBLIC UTILTIES UNDER THE FEDERAL POWER ACT	)	DOCKET NO. RM93-19-000

INITIAL COMMENTS OF THE IDAHO PUBLIC UTILITIES COMMISSION TO THE FERC'S NOTICE OF TECHNICAL CONFERENCE AND REQUEST FOR COMMENTS

IDAHO PUBLIC UTILITIES COMMISSION
472 W. WASHINGTON
BOISE, ID 83720-6000
208-334-3912

MARSHA H. SMITH
PRESIDENT

DEAN J. MILLER
COMMISSIONER

RALPH NELSON
COMMISSIONER

DATED October 6, 1993

willing to pay embedded costs for the transmission capacity it uses which is a benefit to the IPP but it is not a benefit to the transmitting utilities and their ratepayers. The only ratepayer group who may benefit from IPP power is the group served by the purchasing utility.

FERC desires to promote "competition and efficiency" (economic as opposed to energy efficiency) in the wholesale electric market. Among various principles, FERC states that the effect on native load (retail customers) shall be "economic neutrality" or "hold harmless." In other words, native load should not have to subsidize wholesale wheeling for others. Herein lies a concern for state regulators because "economic neutrality" in this case is only valid at one particular moment in time. If a utility has committed a portion of its transmission grid capacity to IPP wheeling, then a portion of existing capacity will not be available for native load growth. Retail ratepayers will end up paying for new transmission capacity before it would ordinarily be needed.

Based on the foregoing the Idaho Commission makes the following recommendation: Wheeling rates paid by IPPs should be sufficiently higher than embedded costs to ensure that native load customers never end up subsidizing an IPP contract. Idaho's concern relates to an IPP being allowed the use of ratepayer-supported facilities without ratepayer knowledge and without just compensation. Embedded costs alone will not provide just compensation. Idaho recommends that the FERC consider instead long-term marginal cost pricing. Idaho does not have the same concern where retail utilities routinely exchange energy which provides a mutual benefit for each ratepayer group. In such case embedded costs are appropriate.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 6th day of October 1993, a true and correct copy of the **INITIAL COMMENTS OF THE IDAHO PUBLIC UTILITIES COMMISSION TO THE FERC'S NOTICE OF TECHNICAL CONFERENCE AND REQUEST FOR COMMENTS** in **FERC Docket RM-93-19-000** was Federal Expressed to the following:

Office of the Secretary
Federal Energy Regulatory Commission
825 North Capital Street N.E.
Washington, D.C. 20426

Brenda Sorrell
Secretary

STATE OF WASHINGTON

WASHINGTON STATE ENERGY OFFICE

925 Plum St. SE, Town Square Bldg #4 • PO Box 43165 • Olympia, Washington 98504-3165

November 16, 1993

Mr. Doug Larson
Executive Director
Western Interstate Energy Board
600-17th Street, Suite 1704 South
Denver, CO 80202

Dear Mr. Larson:

The Energy Office has filed comments in response to a Federal Energy Regulatory Commission (FERC) inquiry concerning transmission pricing policies. I am enclosing a copy of our comments for your review and comment. We believe that transmission pricing and access are likely to be major issues for the Northwest in the next few years. Competition in electric generation, mandatory access provisions of the Energy Policy Act of 1992, and increasing difficulty in siting new transmission lines will make transmission issues more important to regional planners.

Our comments urged FERC to adopt pricing policies that encourage regional planners to improve the efficiency of the interconnected transmission system. We also suggested that pricing policies should encourage broad-based planning that considered transmission, generation, demand side resources, and distribution as interrelated pieces of a comprehensive energy delivery system. FERC should rely on regional planners for guidance on appropriate pricing signals.

We suggested that FERC's pricing policies consider environmental and other impacts of new transmission and related facilities. We also urged FERC to apply consistent pricing principles, regardless of the particular statute under which it considers particular transmission pricing proposals.

We would be interested in your reaction to our comments. Please address them to Deborah Ross, at this address.

Sincerely,

Judith Merchant
Director

JM/dr/ay
O-L4-52W

Enclosure

956-2 ... SCAN 494-2000 Telefax (206) 956-2217 TDD (206) 956-2218

STATE OF WASHINGTON
WASHINGTON STATE ENERGY OFFICE
925 Plum St. S.E. Town Square Bldg #4 • PO Box 43165 • Olympia, Washington 98504-3165

November 4, 1993

Ms. Lois D. Cashell
Federal Energy Regulatory Commission
Office of the Secretary
825 North Capitol Street, N.E.
Washington, D.C. 20426

Subject: Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Docket No. RM93-19-000

Dear Ms. Cashell:

Enclosed please find the original and fourteen copies of comments on the above-captioned inquiry.

Sincerely,

Judith Merchant
Director

JM/jk
M-L3-72doc

Enclosures

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

INQUIRY CONCERNING THE COMMISSION'S PRICING POLICY FOR TRANSMISSION SERVICES PROVIDED BY PUBLIC UTILITIES UNDER THE FEDERAL POWER ACT	DOCKET NO. RM93-19-000

COMMENTS OF THE WASHINGTON STATE ENERGY OFFICE

The Washington State Energy Office (WSEO) is pleased to provide comments on the Federal Energy Regulatory Commission's (FERC's) inquiry on transmission pricing policy. WSEO's mandate is to assist state energy decision makers in acquiring and operating cost effective energy resources, consistent with environmental and other interests and with the regional power plan developed by the Northwest Power Planning Council. Accordingly, these comments accordingly focus on transmission pricing issues that have the potential to affect the acquisition, siting and management of energy resources in the State of Washington and the Pacific Northwest region. These include issues raised by questions 1, 3, 4, 6, 20, 21, 22, and 23 of the FERC Staff Discussion Paper, as well as an additional question raised in the Commission's inquiry that the Discussion Paper did not cover.

The WSEO is also a member of the Committee on Regional Electric Power Cooperation and has endorsed the comments filed by the Committee. Our comments are consistent with the comments and recommendations made by the Committee.

Summary

These comments make the following main points:

- It is federal policy to promote the development and operation of a mechanism that considers transmission, generation and demand side management as interrelated pieces of a comprehensive energy delivery system. The Commission has an opportunity to develop transmission pricing policies that encourage not only efficient building and operation of transmission, but also efficient building and operation of all electricity facilities and services.

- Pricing based on incremental or embedded cost of transmission *alone* will not provide an incentive for planning and operating a comprehensive energy delivery system.

- FERC should adopt a pricing policy that considers not only the impact of transmission on existing generation but also on comprehensive energy delivery systems. Prices should also reflect the environmental and other impacts of transmission-related facilities. For example, a broadly-based "opportunity cost" pricing policy could influence the planning, siting and operation of generation and transmission resources. The Commission should continue its policy of examining opportunity cost pricing proposals on a case-by-case basis. The Commission should take into consideration the unique geographic, demographic, historical and institutional features of each generation and transmission system in examining any proposed opportunity cost pricing proposal

utilities may gradually lose the advantages of being able to control siting and sizing of new generation and the matching of new resources with the grid.

Second, and at the same time, increasing concern over environmental impacts of transmission lines has made siting of new lines exceedingly difficult.

Transmission pricing can play a crucial role in sending signals to utilities and others about the benefits of the development and implementation of a comprehensive energy delivery system. The Staff notes that the historic prevalence of "bundled" power transactions, where a utility or independent power producer (IPP) sells a packaged service of transmission and generation, "allows the parties to share the benefits associated with the sale of a bundled generation and transmission service." Although the Discussion Paper does not spell out these benefits, presumably the Staff is referring at least in part to the advantages of comprehensive energy delivery systems. We concur with Staff that these benefits must not be lost in any pricing policy adopted by the Commission. In fact, FERC should actively pursue pricing policies designed specifically to further comprehensive energy delivery systems. A "broad opportunity cost pricing" policy such as we describe further below in response to question 6 is an example of one such policy. Others may exist.

2. Differences between electric transmission system and natural gas pipeline industry.

The Commission has made significant progress in revolutionizing the natural gas industry's delivery mechanism in a series of historic orders culminating in Order 636 in 1992. We commend the Commission for undertaking a similar review of the electric delivery mechanism at this crucial point in time when access to the transmission grid is becoming increasingly important, and at the same time increasingly difficult.

Electricity is different from natural gas in some significant ways, both physical and institutional. Physically, the electric system is different in at least three ways.

- First, the electric grid, unlike the natural gas pipeline network, does not generally contain the valve and switch system to direct the flow of energy. William Hogan notes in his Electricity Journal article that

> by and large, the electric grid was built purposely without "valves" to capture the huge reliability benefits that come from allowing nature -- not contracts -- to manage the flow.[3]

As noted in the Staff Discussion Paper, there are instances, for example in the Southwest, where phase shifters have been installed to redirect the flow of current and prevent instability of the grid. However, these phase shifters have reduced the interconnectedness of the Western grid and therefore reduced the number of economic transactions that are possible among Western utilities.

A second difference between gas and electric utilities relates to stability. The Western transmission system, for example, consists partly of a few large and long transmission lines connecting urban centers. This type of system is unstable -- that is, the loss of one line can create failures of other parts of the system. Accordingly, the Western Systems Coordinating Council has developed a rating system that rates transmission lines not only by their thermal capacity but also by their ability to carry the load of other lines on the grid when those lines are incapacitated. For this reason, the existence of lines that are either oversized or undersized relative to neighboring transmission lines can create significant

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[3]Hogan, W., "Electric Transmission: A New Model for Old Principles," Electricity J., March 1993.

not comment on whether the increased prevalence of unbundling transmission services is good or bad per se. We think it is possible, however, to design unbundled transmission prices that reflect the benefits of comprehensive planning and operation. We will offer one such methodology in response to Staff question 6 below.

4. **Comprehensive energy delivery mechanisms should be designed and executed on a regional level.**

We have advocated here that FERC should establish pricing policy and approve individual rates that offer an incentive to plan, execute, and operate a comprehensive energy delivery system that fully takes advantage of the synergies among transmission, generation and demand side resources. The planning, execution and operation of the energy delivery system should take place at the regional level, preferably by the utilities and independent power producers who are directly affected by additions to system demands. Regional planning should be carried out in a responsible and reliable fashion, and should be able to provide evidentiary support for prices that are consistent with the regional plan.

The Northwest Power Act of 1980 established the Northwest Power Planning Council, whose responsibility was in part to develop a "general" regional plan for the Northwest states. To date, however, the Council's plans have not addressed either transmission concerns or the impact of siting and operating specific plants on regional interchanges and operations. Nor does any other regional body currently engage in review of specific generating plants or demand side resources to determine whether they are optimally sized and sited to meet the needs of the regional grid. WSEO believes that the time has come to include some regional generation and demand side resource planning that considers the impact of these resources on the regional transmission grid and facilitates economic exchanges. If done correctly, FERC can then approve prices for transmission that provide signals that are consistent with the provisions of the regional plan. Whether this planning function is performed by regional transmission groups (RTGs), the WSCC or some other body need not be determined at this time.

With these initial comments and conclusions, we turn to the questions raised in the inquiry and staff comments.

Response to Staff Questions

Question 1: Comment on Staff's proposed criteria for assessing transmission pricing reform.

WSEO agrees with Staff's proposed criteria for assessing transmission pricing reform. We would add the following criteria, which we believe are consistent with existing federal statutory authority and/or policy:

First, transmission pricing policy should promote efficient planning, siting, use of and investment in *all* energy resources, not only transmission resources. This is consistent with the Staff's statement in the introduction that "it is important to provide transmission price signals that accommodate the efficient operation of existing generating plants while also encouraging least cost investment in new plants." This is also consistent with the transmission pricing policy enunciated in section 212 of the FPA as amended by NEPACT which requires that prices for FERC-mandated wheeling "promote the economically efficient transmission *and generation* of electricity" (emphasis added).

Second, transmission pricing policies should reflect the environmental and other external costs of new transmission siting and operation. Currently, the environmental impacts of new lines are considered qualitatively at most, for example in environmental impact statements prepared for entities required to comply with the National Environmental Policy Act. If wheeling utilities charged a price for

integrated resource planning effort of utilities and other planners. (See Department of Energy, Draft Five Year Integrated Resource Program: "The Vision of Distributed Generation." EPRI Journal at 8 (April/May 1993).)

Although we agree with Dr. Hogan that transmission and generation should be planned in an integral fashion, we do not agree that only centralized dispatch can take advantage of these synergies. Provided that generating and demand side resources are planned and sited to take full advantage of the transmission grid, and that in turn the transmission grid is planned and sited to take advantage of generating and demand side resources, many of these synergies will occur even in the absence of central dispatch.

Thus, impacts of transmission services on generation and demand side management (and vice versa) are not only a "cost" incurred in wheeling but in many cases are an economic alternative that deserves greater recognition. We will suggest one way in which these costs could be reflected in transmission prices further below.

2. Environmental and other externalities. Where we site of new transmission facilities (and other related resources) to meet the needs of transmission customers indirectly affects the population, for example through impacts on wildlife, aesthetics and noise level, and creation of electromagnetic fields. Indeed, opposition to these impacts is making it increasingly difficult to site new transmission facilities. To a certain extent, the complex permitting process often necessary to site new facilities internalizes these impacts. Even when facilities have been sited, however, some residual impacts remain that have not been mitigated through the permitting process.

The Bonneville Power Administration (BPA) incorporates environmental "values" in its cost-benefit analyses of new transmission lines. (See, for example, the Draft Environmental Impact Statement for the Non-Federal Participation in the Third AC Intertie.) However, it is unclear whether these values will be incorporated into pricing proposals. Doing so would help to signal to transmission customers the full cost of the service being provided.[8]

Question 4. How does the unbundling of transmission service affect incentives?

The key issue in any unbundling is the definition of the new unbundled services. The services must be unambiguous and measurable. The buyer and seller must be able to agree on the quantity, quality, and terms of delivery; the services agreed on must be technically deliverable; and agreements must be enforceable. For unbundling to be beneficial, different customers should desire different combinations of the services being unbundled and the unbundling should allow for more efficient pricing, where services provided are priced close to their marginal cost and investment costs are borne by those whose actions cause the investments to be made.

The unbundling of city gate natural gas sales into wellhead sales and transportation and the further unbundling of transportation into transportation service and capacity are good examples of how unbundling should work. These services replaced the bundled service of delivered gas, priced more or less at average cost, with the unbundled services of undelivered gas, sold at market price; delivery, priced more or less at marginal cost; and capacity, with the capacity owner responsible for total cost but able to

[8]We will not address in this forum the problem of ensuring that the affected population is compensated for the environmental impacts of transmission and related resources. A number of suggestions for dealing with this have been made in the extensive literature emerging on environmental externalities of energy resources.

broader definition of opportunity cost would provide correct signals to utilities and other planners that the least cost solution to transmission problems may include additional generation or demand side resources, and that transmission customers will compensate utilities that rely on these "alternative" resources to the benefit of the entire grid.

Question 20. ***Does the failure of postage-stamp rates to recognize distance create important cross subsidies between long-distance and short-distance transfers?***

Question 21. ***How much do transmission costs vary with distance and can such costs be easily quantified?***

Question 23. ***Assess the benefits and problems of specific alternatives to the contract path approach and the need for such alternatives.***

These questions will be addressed together.

Pricing approaches should provide incentives for cost-effective transmission siting and sizing decisions. These may vary substantially from region to region. In the West, while overall transmission costs may vary with distance, costs *per kilowatt* may bear little relation to the length of the transmission line over which the power is being transmitted. As noted in footnote 14 of the Discussion Paper, the Western Systems Coordinating Council (WSCC) has established a regional rating system for transmission that studies the effect of the addition of new transmission and rates the line according to the incremental transfer capability that the transmission brings. Often, stability and other considerations limit the incremental transfer capability to well below the thermal load of the line. In these cases, the cost per kilowatt over that line could be substantially more than the cost per kilowatt over a line whose transfer capability approached thermal constraints.

One approach mentioned in the Discussion Paper remarks on the WSCC's line rating methodology, and suggests that a pricing scheme based on contribution to capital based on the line rating would be feasible. The brief discussion of the WSCC system highlights the need to tailor pricing approaches to the specific features of each region's transmission, generation and demand side system. A pricing approach based on the WSCC line rating system would appear to be promising for Western utilities. FERC should ensure that such an approach is capable of reflecting synergies among generation, demand side and transmission and should establish prices that provide an incentive to capture these synergies.

Question 22. ***Do postage-stamp or distance-sensitive rates provide adequate price signals about the location of new generators? If not, how can transmission prices help promote good location decisions?***

Any transmission prices that are based solely on the cost of either existing or new transmission will not provide adequate signals for least cost planning and siting of new generation or demand side resources. As noted in response to question 3, FERC should adopt a pricing methodology that encourages least cost solutions to an integrated generation, demand side, and transmission grid. This necessarily includes consideration of the relative costs of generation and demand side resources that in some cases can offer a cost effective alternative to new transmission. Neither postage stamp nor distance-based rates necessarily reflect either the cost of providing additional capacity or the value of removing existing constraints or preventing future bottlenecks.

The "broad opportunity cost" approach described in response to question 6 above could be one such methodology. Others may exist as well.

significant impacts on the entire transmission grid. Therefore, it could be detrimental to integrated planning if a potential generator could "shop around" for a location that offered the best transmission prices, unless price differences were entirely due to cost differences. We would therefore favor a FERC approach that established a uniform pricing policy for transmission regardless of whether FERC approved prices under section 205 of the FPA, section 212 of the FPA, or under the Columbia River Act.

This is not to say that the price per kilowatt of transmission should be uniform; differences in cost and other features of each utility's transmission system or individual paths may dictate different prices. However, a uniform application of pricing policies among the various transmission owners in the region would assist in sending correct price signals concerning the cost of providing transmission services to all users of the regional grid.

We believe that the three statutory provisions can be read consistently. Of the three statutes, section 212(a) is the most specific concerning the criteria FERC must apply. We agree with the principles expressed in section 212(a). Moreover, FERC has already been applying much the same principles to transmission rates approved under section 205 (in *NU* and *Penelec*). The one criterion noted in section 212(a) that FERC has not explicitly referred to in its transmission pricing orders, to our knowledge, is the second criterion, that is: "promote the economically efficient transmission and generation of electricity." While FERC orders have sought to promote economically efficient *transmission* of electricity, they have not stressed the interconnection between transmission and generation efficiency. However, the District of Columbia Circuit, in upholding FERC's order in the Western Systems Power Pool case, noted that one of the purposes of the Pool and its negotiated pricing provisions is "to reduce costs through coordination -- that is, to ensure that electricity is always generated by the least expensive means available, then moved through purchase or exchange to where it is needed." Environmental Action v. Federal Energy Regulatory Commission, ___ F.2d ___, slip op. at 5. FERC's approval of the WSCC was pursuant to section 205 of the FPA.

All of FERC's pricing policies should provide signals to coordinate transmission and generation planning and operation. Therefore, FERC in its section 205 rate approvals should apply the same criterion of promoting economically efficient transmission and generation of electricity as it will in its section 212(a) orders.

Sections 9 and 10 of the Columbia River Transmission Act likewise provides the flexibility for FERC to apply the same criteria for prices set by the Bonneville Power Administration for transmission. That Act requires that rates be set "with a view to encouraging the widest possible diversified use of electric power ..." Thus, recovery of transmission cost has never been the sole criterion for setting BPA transmission prices. Enactment of the Northwest Power Act in 1980 established BPA's role in carrying out the regional planning goals of that Act. BPA's transmission rates should contain pricing signals that contain incentives to plan and operate generation and demand side resources that are consistent with the regional energy plan. Although the process for approving BPA rates is somewhat different from rates filed by other transmission owners, FERC must ultimately approve BPA filed rates under the Columbia River Transmission Act. FERC must also review wheeling rates under section 212(i) to determine whether they are just, reasonable, and nondiscriminatory. In so doing, we urge that FERC apply the same pricing principles as it does for other Western transmission rate filings.

constructing additional facilities or ...lifying existing facilities. In effect, ...transmitting utility may be able to treat such a request as two separate transactions—one for service on existing facilities and the other as a request involving expansion decisions. Furthermore, where there are alternative, less expensive means of satisfying all or a portion of a transmission request, the Commission expects the transmitting utility to explore such alternatives (e.g., redispatching certain generating units to alleviate a constraint).

[FR Doc. 93-17216 Filed 7-20-93; 8:45 am]
BILLING CODE 6717-01-M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 510

Animal Drugs, Feeds, and Related Products; Change of Sponsor Name and Address

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

...MARY: The Food and Drug ...inistration (FDA) is amending the animal drug regulations to reflect a change of sponsor name and address from Anaquest, Inc., to Anaquest, Inc., A Subsidiary of BOC Health Care, Inc.

EFFECTIVE DATE: July 21, 1993.

FOR FURTHER INFORMATION CONTACT: Judy M. O'Haro, Center for Veterinary Medicine (HFV-238), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301-295-8737.

SUPPLEMENTARY INFORMATION: Anaquest, Inc., Bernards/78, 110 Allen Rd., Liberty Corner, Bernards Township, NJ 07938, has informed FDA of a change of sponsor name and address to Anaquest, Inc., A Subsidiary of BOC Health Care, Inc., Liberty Corner, NJ 07938-0804. Accordingly, the agency is amending the regulations in 21 CFR 510.600(c)(1) and (c)(2) to reflect the change of sponsor name and address.

List of Subjects in 21 CFR Part 510

Administrative practice and procedure, Animal drugs, Labeling, Reporting and recordkeeping requirements.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under ...ority delegated to the Commissioner ...od and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR part 510 is amended as follows:

PART 510—NEW ANIMAL DRUGS

1. The authority citation for 21 CFR part 510 continues to read as follows:

Authority: Secs. 201, 301, 501, 502, 503, 512, 701, 706 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 321, 331, 351, 352, 353, 360b, 371, 376).

2. Section 510.600 is amended in the table in paragraph (c)(1) by removing the entry for "Anaquest, Inc.," and by adding in its place a new entry for "Anaquest, Inc., A Subsidiary of BOC Health Care, Inc.," and in the table in paragraph (c)(2) in the entry for "010019" by revising the sponsor name and address to read as follows:

§ 510.600 Names, addresses, and drug labeler codes of sponsors of approved applications.

* * * * *

(c) * * *

(1) * * *

Firm name and address	Drug labeler code
* * * * *	
Anaquest, Inc., A Subsidiary of BOC Health Care, Inc., Liberty Corner, NJ 07938-0804	010019
* * * * *	

(2) * * *

Drug labeler code	Firm name and address
* * * * *	
010019	Anaquest, Inc., A Subsidiary of BOC Health Care, Inc., Liberty Corner, NJ 07938-0804
* * * * *	

Dated: July 13, 1993.

George A. Mitchell,

Director, Office of Surveillance and Compliance, Center for Veterinary Medicine.

[FR Doc. 93-17210 Filed 7-20-93; 8:45 am]
BILLING CODE 4160-01-F

21 CFR Part 520

Oral Dosage Form New Animal Drugs; Neomycin Sulfate Solution

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect approval of an abbreviated new animal drug application (ANADA) filed by The Upjohn Co. The ANADA provides for the oral use of a generic neomycin sulfate solution for the treatment and control of colibacillosis in cattle (excluding veal calves), swine, sheep, and goats.

EFFECTIVE DATE: July 21, 1993.

FOR FURTHER INFORMATION CONTACT: Melanie R. Berson, Center For Veterinary Medicine (HFV-135), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301-295-8643.

SUPPLEMENTARY INFORMATION: The Upjohn Co., Kalamazoo, MI 49001-0199, filed ANADA 200-113, which provides for the oral use of a generic 200 milligram/milliliter (mg/mL) neomycin sulfate solution (Biosol® liquid) for the treatment and control of colibacillosis (bacterial enteritis) caused by *Escherichia coli* susceptible to neomycin in cattle (excluding veal calves), swine, sheep, and goats. The drug is administered at 10 mg neomycin sulfate per pound of body weight per day in divided doses.

Approval of ANADA 200-113 for The Upjohn Co.'s Biosol® liquid is as a generic copy of The Upjohn Co.'s NADA 11-315 for Neomix® 325 soluble powder. The ANADA is approved as of June 28, 1993, and the regulations are amended by adding new § 520.1485 (21 CFR 520.1485) to reflect the approval.

In accordance with the freedom of information provisions of part 20 (21 CFR part 20) and § 514.11(e)(2)(ii) (21 CFR 514.11(e)(2)(ii)), a summary of safety and effectiveness data and information submitted to support approval of this application may be seen in the Dockets Management Branch (HFA-305), Food and Drug Administration, rm. 1-23, 12420 Parklawn Dr., Rockville, MD 20857, between 9 a.m. and 4 p.m., Monday through Friday.

The agency has carefully considered the potential environmental effects of this action. FDA has concluded that the action will not have a significant impact on the human environment, and that an environmental impact statement is not required. The agency's finding of no significant impact and the evidence supporting that finding, contained in an environmental assessment, may be seen in the Dockets Management Branch (address above) between 9 a.m. and 4 p.m., Monday through Friday.

List of Subjects in 21 CFR Part 520

Animal drugs.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR part 520 is amended as follows:

transmission services requests additional flexibility to schedule multiple resources to meet its needs (e.g., network service), the request for services should contain a description of the requested services in sufficient detail to permit the transmitting utility to model the additional services on its transmission system.

(5) The names of any other parties likely to provide transmission service to deliver electric energy to, and receive electric energy from, the transmitting utility's grid in connection with the requested transmission services.

(6) The proposed dates for initiating and terminating the requested transmission services.

(7) The total amount of transmission capacity being requested.

(8) To the extent it is known or can be estimated, a description of the "expected transaction profile" including load factor data describing the hourly quantities of power and energy the party requesting transmission services would expect to deliver to the transmitting utility's grid at relevant points of interconnection. In the event delivery is to multiple points within the transmitting utility's electric control area, the requestor should describe, to the extent it is known or can be estimated, the expected load (over a given duration of time) at each such delivery point.

(9) Whether firm or non-firm service is being requested. Where a party requests non-firm service, it should specify the priority of service it is willing to accept, or the conditions under which it is willing to accept interruption or curtailment, if known.

(10) A statement as to whether the request is being made in response to a solicitation and a copy of the solicitation if publicly available. This will help the transmitting utility determine whether requests for transmission service are duplicative or mutually exclusive of requests filed by other parties.

(11) The proposed rates, terms and conditions for the requested transmission services as required by section 213(a). It is not necessary for the requestor to propose a specific numerical rate. Rather, a party requesting transmission services can fulfill the rates, terms and conditions requirement by specifying a rate methodology (e.g., embedded or incremental cost) or by referencing an existing formula rate, transmission tariff, or transmission contract. The validity of the good faith request will not depend on the rates proposed by the party requesting transmission services. This requirement is not intended to allow utilities to delay responses to requests for transmission services, or to deny requests for transmission services on the basis of an overly rigid or technical approach, to the "rates, terms and conditions" element of the request.

(12) Any other information to facilitate the expeditious processing of its request. Such information will improve the negotiation process, reduce costs, and will improve chances to arrange the requested transmission without resorting to section 211 application procedures before the Commission.

(c) *Components of a Reply to a Good Faith Request.* The Commission generally considers the following to constitute the minimum components of a reply to a good faith request for transmission services under section 213(a):

(1) Unless the parties agree to a different time frame, the transmitting utility must acknowledge the request within 10 days of receipt. The acknowledgement must include a date by which a response will be sent to the party requesting transmission services and a statement of any fees associated with responding to the request (e.g., initial studies).

(2) The transmitting utility may ask the applicant to provide clarification of only the information needed to evaluate and process a "good faith" request. If the person requesting transmission services believes the transmitting utility is attempting to frustrate the process by making excessive requests for clarification, it may raise this issue if, and when, it files a request for a section 211 order with the Commission.

(3) The transmitting utility must respond to a request within 60 days of receipt or some other mutually agreed upon response date. If both parties agree to an alternative schedule, the agreement must be in writing and signed by both parties.

(4) If the transmitting utility determines that it can provide all the requested services from existing capacity, it should respond by offering the party requesting transmission services an executable service agreement that at a minimum contains the following information:

(i) A description of the proposed transmission rate and any other costs. It is not necessary for the proposed service agreement to contain a fully developed cost-of-service. However, the agreement should explain the basis for the charges for each component of service, including the unbundled components of any transmission rate as well as any other charges.

(ii) The proposed service agreement should explicitly describe all of the applicable terms and conditions of the transmission services provided under the agreement.

(iii) The transmitting utility should accompany the proposed service agreement with a clear statement of the time during which the offer to provide the transmission services will remain open. An open agreement offer may obligate the seller while imposing no countervailing obligation on the purchaser, and an unexecuted contract potentially ties up transmission facilities, thus jeopardizing the availability and price for subsequent requests that would use the same facilities. However, at a minimum, a transmitting utility should permit the party requesting transmission services sufficient time to review service agreements and coordinate multiple stages of joint transactions.

(5) If the transmitting utility determines that it must construct additional facilities or modify existing facilities to provide all or part of the requested services, it must:

(i) Identify the specific constraints and their duration that prevent it from providing all the requested services and explain how these constraints prevent it from providing all the requested services or the desired level of firmness.

(ii) Provide to the applicant all studies, computer input and output data, planning, operating and other documents, work papers, assumptions and any other material that forms the basis for determining the constraints.

(iii) Offer to the applicant an executable agreement under which the applicant agrees to reimburse the transmitting utility for all costs of performing any studies necessary to determine what changes to the transmitting utility's grid are needed to overcome the constraint and provide the requested services, their cost, and the estimated time to complete them. At a minimum, the proposed agreement should contain the following:

(A) An estimate of the cost of the study and the time required to complete it, and

(B) A commitment to supply to the party requesting transmission services all computer input and output data, planning, operating and other documents, work papers, assumptions and any other material used to perform the study.

(iv) If a transmitting utility determines that it can provide part but not all of the requested services without building new facilities, it should inform the applicant of any portion of the requested services that can be performed without

ather creatively and constructively to minate constraints and to explore alternative transmission approaches to efficiently coordinate planning for all transmission users.

V. Information Collection Statement

The Office of Management and Budget's (OMB) regulations at 5 CFR 1320.12 require that OMB approve certain information and recordkeeping requirements imposed by an agency. The information collection requirements in this policy statement are contained in new 18 CFR 2.20.

The Commission is issuing this Policy Statement with the information requirements to carry out its regulatory responsibilities to implement the transmission provisions of the Energy Policy Act of 1992. As provided by the Energy Policy Act, section 211(a) provides that the Commission may not issue an order directing a transmitting utility to provide transmission services unless the party requesting such an order has requested the transmission services from the transmitting utility at least 60 days before applying to the Commission. A request for transmission services is, then, a condition precedent to the Commission's ability to order nsmission services under section 211 he Federal Power Act. Section 213(a) of the FPA requires a response by a transmitting utility when any electric utility, Federal power marketing agency, or any other person generating electric energy for sale or resale makes "a good faith" request to a transmitting utility to provide wholesale transmission services under specific rates, charges, terms and conditions of service. The Commission's Office of Electric Power Regulation uses the data for determination of an acceptable transmission request for service of a wheeling order under section 211 of the FPA, and for a determination as to whether a transmitting utility has provided a sufficient reply under the newly amended statute. These collections of information are intended to be the minimum elements needed to make good faith request and a proper response.

The Commission is submitting to the Office of Management and Budget a notification of these proposed collections of information. Interested persons may obtain information on these reporting requirements by contacting the Federal Energy Regulatory Commission, 941 North tol Street, NE., Washington, DC 26 [Attention: Michael Miller, Information Policy and Standards Branch, (202) 208–1415]. Comments on the requirements of this rule can be sent to the Office of Information and Regulatory Affairs of OMB, Washington, DC 20503, (Attention: Desk Officer for Federal Energy Regulatory Commission).

VI. Public Comment Procedures

The Commission invites interested persons to submit written comments on the matters and questions raised in this Policy Statement. An original and 14 copies of the comments must be filed with the Commission no later than August 20, 1993. Comments should be submitted to the Office of the Secretary, 825 North Capitol Street NE., Washington, DC 20426, and should refer to Docket No. PL93–3–000.

All written comments will be placed in the Commission's public files and will be available for inspection in the Commission's Public Reference Room at 941 North Capitol Street NE., Washington DC 20426, during normal business hours.

List of Subjects in 18 CFR Part 2

Administrative practice and procedure, Electric power, Natural gas, Pipelines, Reporting and recordkeeping requirements.

In consideration of the foregoing, the Commission amends part 2, chapter I, Title 18 of the Code of Federal Regulations as set forth below.

By the Commission.

Lois D. Cashell,

Secretary.

PART 2—GENERAL POLICY INTERPRETATIONS

1. The authority citation for part 2 is revised to read as follows:

Authority: 15 U.S.C. 717–716w, 3301–3432; 16 U.S.C. 792–825y, 2601–2645; 42 U.S.C. 4321–4361, 7101–7352.

2. Part 2 is amended by adding § 2.20, to read as follows:

§ 2.20 Good faith requests for transmission services and good faith responses by transmitting utilities.

(a) *General Policy.* (1) This Statement of Policy is adopted in furtherance of the goals of sections 211(a) and 213(a) of the Federal Power Act, as amended and added by the Energy Policy Act of 1992.

(2) Under section 211(a), the Commission may issue an order requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) only if an applicant has made a request for transmission services to the transmitting utility that would be the subject of such order at least 60 days prior to its filing of an application for such order. The requirement in section 211(a) that an applicant make such a request will be met if such an applicant has, pursuant to section 213(a) of the FPA, made a good faith request to a transmitting utility to provide wholesale transmission services and requests specific rates and charges, and other terms and conditions.

(3) It is the Commission's intention to apply the standards of this Statement of Policy when determining whether and when a valid "good faith" request for service was made.

(4) It is the Commission's intention to encourage an open exchange of information that exhibits a reasonable degree of specificity and completeness between the party requesting transmission services and the transmitting utility.

(5) The Commission intends to apply this Statement of Policy so as to carry out Congress' objective that, subject to appropriate terms and conditions and just and reasonable rates, in conformance with section 212 of the FPA, access to the electric transmission system for the purposes of wholesale transactions be more widely available.

(b) *The Components of a good faith request.* The Commission generally considers the following to constitute the minimum components of a good faith request for transmission services:

(1) The identity, address, telephone number, and facsimile number of the party requesting transmission services, and the same information, if different, for the party's contact person or persons.

(2) A statement that the party requesting transmission services is, or will be upon commencement of service, an entity eligible to request transmission under sections 211(a) and 213(a) of the FPA.

(3) A statement that the request for transmission services is intended to satisfy the "request for transmission services" requirement under sections 211(a) and 213(a) of the FPA, and that the request is not a request for mandatory retail wheeling prohibited under section 212(h) of the FPA.

(4) The party requesting transmission services should specify the character and nature of the services requested. Some types of service may require more detailed information than others. Where point-to-point service is requested, the party requesting transmission services should specify the anticipated point(s) of receipt to the transmitting utility's grid and the anticipated point(s) of delivery from the transmitting utility's grid. Where a party requesting

Component (3)—The Requirement That the Transmitting Utility Respond Within 60 Days

When the transmitting utility acknowledges receiving a request for transmission services and responds by notifying the party making the request of fees associated with the evaluation of a transmission request, it should specify the date by which it will respond to the request or initiate negotiations that could lead to agreement on some mutually acceptable date other than that set by the 60-day clock. The fees for evaluating transmission service requests should be set based on the cost of processing the request.

Component (4)—The Transmitting Utility's Response If It Believes It Can Provide the Requested Service From Existing Capacity

When a transmitting utility determines that it can provide the requested services from existing capacity, it should proceed to offer the party requesting the services a proposed service agreement covering the service that it will provide. The contract should contain detailed specifications of the price at which the transmitting utility proposes to provide the services.

It is not necessary for the proposed service agreement to contain a regulatory "cost-of-service" study of the kind included in rate filings by public utilities. However, the agreement should explain the basis for the charges for each component of service, including the unbundled components of any transmission rate and any other charges.[32] In other words, the agreement should clearly lay out the charges for each component of the proposed service and the total price the party requesting the service would be expected to pay. Similarly, the agreement should explicitly describe all of the applicable terms and conditions of the transmission services provided under the contract.

The transmitting utility should accompany the agreement with a clear statement of the time during which the offer to provide the transmission services will remain open. The Commission recognizes that an open contract offer obligates the seller while imposing no countervailing obligation on the purchaser, and that an unexecuted contract potentially ties up transmission facilities, thus jeopardizing the availability and price for subsequent requests that would use the same facilities.

On the other hand, entities that might request transmission services may frequently be in the position of bidding on a power solicitation or negotiating other related contracts. In such an instance, the transmission agreement is only one element of the whole transaction, and the purchaser may need to finalize all of the pieces at one time. Under these circumstances, the purchaser might want some sort of reservation or contingency arrangement that would extend the period during which the contract is held open until a time certain or until a set of events reaches completion. Preferably, transmitting utilities and the party requesting the services can be flexible and resolve these problems by mutual agreement. However, the Commission feels that, at a minimum, a transmitting utility should permit the party requesting the service sufficient time to review agreements and coordinate multiple stages of joint transactions.

Component (5)—What the Transmitting Utility Should Do If It Determines That It Must Construct Additional Facilities or Modify Existing Facilities in Order To Provide All or Part of the Requested Services

In situations in which the transmitting utility determines that it must construct additional facilities or modify existing facilities to provide all or part of the requested services, the transmitting utility must provide a fully documented description of why and for how long its grid is and will be constrained. Only by providing full technical information to a person requesting transmission services can a transmitting utility establish a productive working relationship for negotiating transmission service contracts.

In addition to explaining the determination of existing constraints, the transmitting utility should offer the party requesting services an executable contract for a study to determine how the constraint can be relieved. The study contract should specify the cost and production time for the study. The study itself should result in a determination of how the transmitting utility will remove the constraint, how long it will take and how much it will cost.

Transmitting utilities will usually be able to remove constraints by arranging for some type of physical expansion of the transmission grid, but there may be ways short of new construction to meet a request for transmission services. A party requesting services may find an alternate transmission path, or may be able to purchase someone else's prior transmission rights.

Since finding alternative means to accommodate a transmission request may require information available only to the transmitting utility, the Commission urges transmitting utilities to consider ways of making such information available to persons requesting transmission services. One way might be to post existing and planned transmission rights sales on an electronic bulletin board so that the parties can engage in informed negotiations.

If a transmitting utility determines that it can provide part but not all of the requested services without building new facilities, it should offer to provide the part of the services that does not require expansion of its transmission facilities under a separate contract. In effect, the transmitting utility may be able to treat such a request as two separate transactions—one for service on existing facilities and the other as a request involving expansion decisions.

C. Other Issues

1. Prioritization of Service Requests

There is no component regarding how the transmitting utility should prioritize service requests. A transmitting utility may find it difficult to prioritize requests in a fair manner, especially if the transmission grid is near capacity and only a limited number of transmission service requests can be accommodated without expansion. Although the Commission recognizes that "first-come, first-served" prioritization will not always produce the most efficient allocation of capacity, at this time it will accept prioritization based on this procedural rule or any reasonable method of allocation. However, the Commission expects that the industry may develop better allocation mechanisms in the future.

2. The Right of an Applicant to File a Section 211 Request After 60 Days

Good faith requests for transmission services can always be brought to the Commission 60 days after the request is made to the transmitting utility if the party making the request finds the transmitting utility's response unsatisfactory. However, we reiterate that these minimum elements are intended to serve as guidelines; they should not be viewed as limiting the negotiating options available to the parties so long as they do not require Commission action. The Commission urges parties to communicate freely and openly with each other and to work

[32] These components may be capital costs, such as interconnection charges, or variable costs, such as charges for transmission losses, that the transmitting utility proposes to charge for the service.

points may not restrict the provision of ...l network service, but could restrict ...ties in requesting system-wide network service.

The Commission understands that the network service issue raises important questions, such as how to price the service and what user rights would be associated with it. Some of these will be addressed in the inquiry concerning transmission pricing that the Commission recently initiated.[11] In this proceeding, we ask the following questions:

Question 1. Does the service specification in Component (4) unduly restrict the ability of parties to request the transmission services that they need? If so, what changes would be appropriate?

Question 2. Does the language in Component (4) give owners of transmission facilities sufficient information to provide network service?

Component (5)—The Names of Other Parties Expected To Be Delivering and/or Receiving Power From the Transmitting Utility

If a requesting party knows that it will need to receive services from multiple transmitting utilities, it should provide such information to the transmitting ...lities. In instances in which the party ...esting services does not know who all the parties will be, however, it should provide whatever information it has and indicate what information is unknown or tentative at the time it makes the request. The transmitting utilities are usually the control area utilities that either are affected by the power flows in question or that would lie on the contract path if two or more transmitting utilities are involved in the transaction. Transmitting utilities need to know which electric control areas will be involved in a transaction.

Component 8—The Expected Transaction Profile

The information supplied by the requesting party and needed by the transmitting utility should be a function of the type of services being requested. Some types of services may require more detailed information than others. The requesting party should provide enough information to permit the transmitting utility to model the power flow impact on its system of both receipts and deliveries. The "expected transaction profile" means the load factor data that describes the flow of power and energy into the transmitting ...y's system, *i.e.*, the hourly ...ities of power the requesting party would expect to deliver to the transmitting utility's grid at points of interconnection between electric control area utilities, if known.

Component 9—The Degree of Firmness of the Requested Service

The Commission will leave it to the party requesting the services to specify how firm a service is being requested. The degree of firmness of transmission service is often categorized as firm or interruptible. However, these designations may not adequately describe the service that is sought. Therefore, the requesting party should indicate the specific degree of firmness that it seeks. This will help to reduce the likelihood of misunderstandings.

Component 10—Requests Made in Response to Solicitations

Persons requesting service in order to submit a bid in a solicitation for generation resources should state the purpose of the requested service and identify the solicitation for which they are requesting service. Naming the solicitation will be helpful, because some solicitations could result in duplicative transmission service requests. The transmitting utility will be better able to gauge the aggregate amount of service it may have to provide if it can group duplicate requests.

Component 11—The Terms and Conditions Requested

Section 213(a) provides that the requestor must propose rates, terms and conditions for the services it is requesting. We do not think that it is necessary for the requestor to propose the exact, detailed rates, terms and conditions. Rather, a party requesting transmission services can fulfill the rates, terms and conditions requirement by specifying a rate methodology (e.g., embedded or incremental cost), an existing transmission tariff, an existing transmission contract or an existing rate. The Commission does not intend to allow utilities to delay responses to requests for transmission services by taking an overly rigid or technical approach to the "rates, terms and conditions" element of the request. It is sufficient if the one requesting the services has made an effort to develop workable terms and conditions and has proposed what it sees as reasonable rates. The transmitting utility is not bound by the requesting party's proposed rates, terms and conditions. It may reject the proposed rates, terms and conditions and propose its own.

Component 12—Additional Information

Finally, to improve overall effectiveness and efficiency, the party requesting the service should include any information that enhances the transmitting utility's ability to evaluate the request. This can improve the ability to negotiate and lower costs for all parties and will improve chances to arrange for the requested transmission without resorting to section 211 procedures before the Commission.

B. Components of a Reply to a Good Faith Request

This Policy Statement contains five components of a reply to a good faith request for transmission services under section 213(a). These are discussed below.

Component (1)—Acknowledgment of Receipt of the Request

A party requesting transmission services may not seek an order from the Commission under section 211 of the FPA unless it has first requested the transmission services from a transmitting utility 60 days before applying to the Commission. That 60-day period begins to run when the transmitting utility receives the request. A transmitting utility should promptly acknowledge receipt of a request for transmission services. Unless the parties agree on a different time frame for the utility's response, a prompt acknowledgment should occur within 10 days. Receipt of the acknowledgement would alert the one requesting transmission services that its 60-day waiting period has begun.

Component (2)—Requests by the Transmitting Utility for Clarification of Information

The Commission believes that a transmitting utility should be able to ask for clarification of a request if the utility needs more information to evaluate the requested services. In the absence of limitations on requests for such clarifications, however, the processing of requests for transmission could be unduly delayed. Therefore, information clarifications sought by the transmitting utility should be limited to facts needed to evaluate the specific services being requested. A requesting party who believes that a transmitting utility is attempting to frustrate the process by making excessive requests for clarifications can raise this issue when it files a request for a section 211 order with the Commission 60 days after the utility has received its request.

[11] See n. 9, *supra*.

requestors and transmitting utilities avoiding or circumventing attempts at negotiation. Likewise, perfunctory responses to requests for transmission services could result in avoiding or circumventing attempts at negotiation.

There is no discussion in the Joint Explanatory Statement of the Committee of Conference to guide us as to whether Congress intended potential section 211 applicants and transmitting utilities to attempt negotiation in order to avoid section 211 proceedings when possible. However, in view of the language, structure, and requirements of section 231(a), we believe that as a policy matter sections 211(a) and 213(a) should be implemented in a manner which encourages negotiation. Therefore, the Commission will adopt standards which: (1) Identify the type of information that would facilitate a section 211(a) request; (2) foster greater competition in wholesale electric markets; (3) encourage coordination and cooperation and (4) encourage negotiated agreements where possible.

This Policy Statement sets forth the elements of what the Commission believes will generally constitute a good faith request under sections 211(a) and 213(a) of the FPA and a proper reply to a good faith request. This proceeding is one of several concurrent proceedings in which the Commission is implementing the transmission provisions of the Energy Policy Act. The other proceedings are: (1) The Commission's Request for Public Comments on the Regional Transmission Group Proposal;[5] (2) Proposed New Reporting Requirements Implementing Section 213(b) of the FPA;[6] and (3) the Commission's inquiry regarding transmission pricing.[7]

This Policy Statement contains only those elements that the Commission would generally look to if a party seeking transmission services were to request an order directing a transmitting utility to provide transmission services under section 211 of the FPA. The Commission encourages those engaged in transmission transactions to devise, on their own initiative, creative ways of solving transmission needs, thus avoiding the delay inevitably resulting from case-by-case resolution by the Commission. The Commission emphasizes that the guidelines set forth in this Policy Statement are neither rigid nor all-encompassing. The Commission encourages negotiation and remains open to suggestions on how to accommodate specific concerns as they arise.

IV. Discussion

A. Components of a Good Faith Request

This Policy Statement contains twelve components of a good faith transmission request. These components are the minimum components that will generally be necessary to provide the transmitting utility with sufficient information so that it can analyze the service request. If a transmitting utility is to be able to analyze a transmission request, the person requesting services must specify the services that it wants. The information that a transmitting utility would need in order to determine how to provide the requested services includes: (1) The identity of the purchaser; (2) assurances that the prospective purchaser of the transmission services is eligible to request the services; and (3) assurances that the Commission is authorized to order the type of services requested under appropriate circumstances.

A good faith request for transmission services should also contain a specific, technical description of the requested services in sufficient detail to permit the transmitting utility to model the additional services on its transmission system. Certain of the technical components of a request for transmission services are discussed below. The others are self-explanatory.

Component (4)—Specifying the Type of Services Requested

Section 211 of the FPA does not place any limit on what is meant by "transmission services," nor does the legislative history suggest any limitation on the nature of the wholesale transmission services the Commission can order under section 211. In the absence of any indication that Congress intended to limit the type of transmission services ordered, any party may request network service under section 211. It is important that the specific language of Component (4) not prevent parties from requesting any type of transmission services, particularly network service. As is the case with any request for transmission under section 211, the Commission will determine whether to order network service on a case-by-case basis.

Although the Commission at this time believes that service more flexible than point-to-point can be ordered under section 211, and thus is a proper subject for good faith requests, parties may submit comments on the limitations, if any, on the Commission's authority to order such service.

The party requesting transmission services should specify the character and nature of the services. The nature of transmission service varies along a continuum, starting with point-to-point service, passing through a form of service that might best be characterized as flexible point-to-point service, and culminating with network service. These terms have no industry-wide accepted definitions. However, the Commission has characterized point-to-point service as involving designated points of entry into and exit from the transmitting utility's system with a designated amount of transfer capability at each point.[8] In a Staff Paper issued with the Commission's recent notice of inquiry concerning transmission pricing, the Commission's staff stated that it understood network service to mean transmission service that allows the user to vary its schedule and points of delivery and receipt on the grid without paying an additional charge for each change.[9]

The Commission invites comments on whether specifying point(s) of receipt and delivery will unduly restrict the ability of parties to request the flexibility of the transmission service that some parties may need. "Network service," for example, involves substantial flexibility in moving power between receipt and delivery points.[10] It is possible that the need for network service will be localized within a control area. An example might be the network service needed by an association of distributors to dispatch their own resources, or by an IPP to sell to multiple buyers. This type of local network service might be combined with flexible point-to-point service to import or export power outside the control area. Alternatively, some parties may wish to request network service over the entire grid of the control area utility, which presumably would involve substantially more flexibility of use. Specifying receipt and delivery

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[5] 57 FR 54,580 (Nov. 19, 1992); 61 FERC ¶61,232 (1992).

[6] 58 FR 17,544 (April 5, 1993); IV FERC Stats. & Regs. ¶32,493 (1993).

[7] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 58 FR 36,400 (July 7, 1993), IV FERC Stats. & Regs. ¶ _____.

[8] Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,768 (1992).

[9] See Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Staff Paper at 13 (Question 18), 58 FR 36,400 (July 7, 1993), IV FERC Stats. & Regs. ¶ _____ (1993).

[10] We note that in the Staff Paper issued in conjunction with the Commission's transmission pricing inquiry, *supra* n.9, persons were asked to comment on whether the staff's definition of network service, contained in that paper, is reasonable. Persons wishing to comment on the parameters of "network service" should do so in that docket.

ceptable to the requestor, the ansmitting utility is required to respond in writing to the requestor within 60 days of receipt of such request or other mutually agreed upon period.

These 60-day requirements make it important that potential section 211(a) applicants, 213(a) requestors, and transmitting utilities have general guidance, as soon as possible, as to what the Commission considers an acceptable transmission request and transmission reply under the newly amended statute. Accordingly, the Commission is adopting this Policy Statement containing such guidelines. The Commission's guidelines are broad enough to encourage individual initiative and negotiation within a flexible framework, leading to accommodations that will encourage optimum access to this country's transmission system.

II. Public Reporting Burden

The Policy Statement establishes new reporting requirements that are the minimum guidelines necessary for a party to request transmission services from a transmitting utility and to ensure the proper response from the transmitting utility. The public reporting burden for these information collections is estimated to average 40 hours per request for the requestor and 160 hours per response for the transmitting utility, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding these burden estimates or any other aspect of these collections of information, including suggestions for reducing the burden, by contacting the Federal Energy Regulatory Commission, 941 North Capitol Street, NE., Washington, DC 20426 [Attention: Michael Miller, Information Policy and Standards Branch, (202) 208–1415], and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for Federal Energy Regulatory Commission).

III. Background

As amended by the Energy Policy Act, section 211(a) provides that the Commission may not issue an order directing a transmitting utility to provide transmission services unless the person applying for an order has requested the transmission services from the transmitting utility at least 60 days before applying to the Commission. A request for transmission services is, then, a condition precedent to the Commission's ability to order transmission services under section 211 of the FPA.

Section 213(a) of the FPA requires a response by a transmitting utility when any electric utility, Federal power marketing agency, or other person generating electric energy for sale for resale makes a "good faith" request to a transmitting utility[2] to provide wholesale transmission services and requests specific rates and charges, and other terms and conditions of service. Section 213(a) provides that unless the transmitting utility accommodates the request on mutually agreeable terms it shall, within 60 days of receipt of the request, or other mutually agreed upon period, provide the person requesting the services with a detailed written explanation of the basis for the transmitting utility's proposed rates, charges, terms and conditions for such services. The written explanation must also contain an analysis of any physical or other constraints affecting the provision of the requested transmission services. Section 213(a) does not define what is meant by a good faith request for transmission services, nor does the FPA elsewhere contain a definition of the term, and the legislative history of the Energy Policy Act is silent on the subject.

The Commission believes that Congress, in enacting section 213(a) of the FPA, intended that potential applicants for transmission services under section 211 of the FPA and transmitting utilities provide one another with as much information as reasonably available concerning requests for, and ability to provide, transmission services, before a person seeking transmission services avails itself of section 211. The Commission further believes that if potential applicants and transmitting utilities exchange detailed information, this will help to encourage constructive business transactions through negotiated agreements. Accordingly, at this early stage of our administration of sections 211 and 213, we find it appropriate to adopt standards which provide for a broad exchange of information. A broad exchange of information will permit transmission requestors to file focused and more detailed applications under section 211(a) and will allow the Commission to expedite section 211(a) applications. It may also further the goal of encouraging negotiated agreements.

In adopting this Policy Statement, the Commission has read section 211(a) in consonance with section 213(a). On its face, section 211(a) requires that a party need only make "a request" to the transmitting utility. Section 211(a) does not use the adjective "good faith" nor does it require that a section 211(a) applicant specify rates, charges, and other terms and conditions of service when making a request.[3] The Commission believes, however, that for purposes of making a section 211(a) "request," a party's request for transmission services should be the same as a "good faith request" made under section 213(a).[4] If an entity does not make a section 213(a) good faith request 60 days before filing a section 211(a) application, the Commission believes that it has the statutory authority to deny such an application on the basis that a proper request was not made pursuant to section 211(a).

There are several reasons why the Commission finds it appropriate to incorporate the 213(a) good faith requirement as part of what will be deemed to be a satisfactory request under section 211(a). First, because sections 211 and 213 both refer to a 60-day time clock which starts when an entity makes a request for services to a transmitting utility, we believe Congress intended the two sections to work in conjunction with one another. If we were to implement section 211(a) so as to require that a party make only "a request" to a transmitting utility 60 days before filing a section 211 application with the Commission, the two sections would not work in a complementary fashion with one another, because a mere "request" may constitute less than a "good faith" request. Second, requiring two standards—one for "requests" and the other for "good faith requests"—could become administratively burdensome and confusing. Third, if we construed section 211 to require mere "post-card" requests, without requiring that a person requesting transmission services file a good faith request and utilize the "request and response" scenario envisioned by section 213(a), the section 213(a) process could be rendered a nullity. Moreover, it could result in

[2] Section 3(23) of the FPA, as added by the Energy Policy Act, 16 U.S.C. 796(23), defines a "transmitting utility" as any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.

[3] Accordingly, as a legal matter the Commission could implement the request requirement under section 211(a) using a more lenient standard than would be used for "good faith" requests under section 213(a). However, as discussed below, as a policy matter we believe it is appropriate to use the same standard.

[4] See Section 2.20(a)(2) of the Policy Statement.

PART 1700—[AMENDED]

1. The authority citation for part 1700 continues to read as follows:

Authority: Pub. L. 91-601, secs. 1-9, 84 Stat. 1670-74, 15 U.S.C. 1471-76. Secs. 1700.1 and 1700.14 also issued under Pub. L. 92-573, sec. 30(a), 88 Stat. 1231.15 U.S.C. 2079(a).

2. Section 1700.14 is amended by adding new paragraph (a)(21) and republishing the introductory text of paragraph (a) to read as follows:

§ 1700.14 Substances requiring special packaging.

(a) *Substances.* The Commission has determined that the degree or nature of the hazard to children in the availability of the following substances, by reason of their packaging, is such that special packaging is required to protect children from serious personal injury or serious illness resulting from handling, using, or ingesting such substances, and the special packaging herein required is technically feasible, practicable, and appropriate for these substances:

* * * * *

(21) *Loperamide.* Preparations for human use in a dosage form intended for oral administration and containing more than 0.045 mg of loperamide in a single package (*i.e.*, retail unit) shall be packaged in accordance with the provisions of § 1700.15(a), (b), and (c).

* * * * *

Sadye E. Dunn,

Secretary, Consumer Product Safety Commission.

List of References

(Note: This list of relevant documents will not be printed in the Code of Federal Regulations.)

1. Memorandum from Rita A. Orzel, Ph.D., HSPS, to Virginia A. White, HSPS, "Loperamide Toxicity," March 4, 1992.

2. Memorandum from Charles Wilbur, HSPS, to Rita A. Orzel, Ph.D., HSPS, "Loperamide: Technical Feasibility, Practicability, and Appropriateness Determination," April 1, 1992.

3. Memorandum from Marcia P. Robins, ECSS, to Rita A. Orzel, Ph.D., HSPS, "Preliminary Assessment of Economic and Environmental Effects of a Proposal to Require Child-Resistant Packaging for OTC Drug Preparations Containing Loperamide," April 6, 1992.

4. Briefing Memorandum with attached briefing package, August 6, 1992.

5. Letter from Beverly L. Black, Director, Federal Regulatory Affairs, American Society of Hospital Pharmacists, to Rita Orzel, December 23, 1992.

6. Memorandum from Marcia P. Robins, ECSS, to Rita A. Orzel, Ph.D., HSPS, "Final Regulatory Flexibility Act Analysis for Proposal to Require Child-Resistant Packaging for OTC Drug Preparations Containing Loperamide," February 19, 1993

7. Memorandum from Jacqueline N. Ferrante, Ph.D., to James F. Hoebel, Acting AED for Health Sciences, "Updated Review of the Children and Poisoning Data Base for Loperamide Ingestions," dated April 20, 1993.

8. Memorandum from Marcia P. Robins, ECSS, to Jacque N. Ferrante, Ph.D., Project Manager, "Market Up-date: Loperamide," dated April 29, 1993.

9. Briefing Memorandum with attached briefing package, June 3, 1993.

[FR Doc. 93-17096 Filed 7-20-93; 8:45 am]

BILLING CODE 6355-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 2

[Docket No. PL93-3-000]

Policy Statement Regarding Good Faith Requests for Transmission Services and Responses by Transmitting Utilities Under Sections 211(a) and 213(a) of the Federal Power Act, As Amended and Added By the Energy Policy Act of 1992

Issued July 14, 1993.

AGENCY: Federal Energy Regulatory Commission DOE.

ACTION: Final rule; policy statement.

SUMMARY: The Federal Energy Regulatory Commission is adopting guidelines setting forth the elements of what generally constitutes a good faith request for transmission services under sections 211(a) and 213(a) of the Federal Power Act (FPA), as amended and added by the Energy Policy Act of 1992, and of a proper reply to that request. The Commission is issuing this Policy Statement as part of its effort to implement the transmission provisions of the Energy Policy Act of 1992.

DATES: Effective July 14, 1993. Comments may be filed on or before August 20, 1993.

ADDRESSES: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol St., NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Andre Goodson (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426. Telephone: (202) 208-2167

Joseph C. Lynch (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426. Telephone: (202) 208-2128

Margaret J. Ness (Technical Information), Office of Economic Policy, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426. Telephone: (202) 208-0019.

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in room 3104, 941 North Capitol Street NE., Washington, DC 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing (202) 208-1397. To access CIPS, set your communications software to use 300, 1200, or 2400 bps, full duplex, no parity, 8 data bits, and 1 stop bit. CIPS can also be accessed at 9600 bps by dialing (202) 208-1781. The full text of this rule will be available on CIPS for 30 days from the date of issuance. The complete text on diskette in WordPerfect format may also be purchased from the Commission's copy contractor, LaDorn Systems Corporation, also located in room 3104, 941 North Capitol Street NE., Washington, DC 20426.

Before Commissioners: Elizabeth Anne Moler, Chair; Vicky A. Bailey, James J. Hoecker, William L. Massey, and Donald F. Santa, Jr.

Policy Statement

Issued July 14, 1993.

I. Introduction

An essential element in implementing sections 211(a) and 213(a) of the Federal Power Act (FPA), as amended and added by the Energy Policy Act of 1992 respectively,[1] is determining what constitutes a good faith transmission request and reply under those sections. This issue is important for two reasons. First, the Commission may not order transmission services under section 211(a) unless the applicant has made a request for such services to the transmitting utility at least 60 days prior to filing an application with the Commission. Second, under section 213(a), unless the transmitting utility agrees to provide transmission services pursuant to a good faith request, at rates, charges, terms and conditions

[1] Public Law 102-486, 106 Stat. 2776 (1992), 16 U.S.C. 824*l*.

UNITED STATES OF AMERICA 64 FERC 61,369
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 141

[Docket No. RM93-10-000]

New Reporting Requirement Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities under the Energy Policy Act of 1992, and Conforming and Other Changes to Form No. FERC-714

FINAL RULE

(Issued September 30, 1993)

AGENCY : Federal Energy Regulatory Commission

ACTION : Final Rule

SUMMARY: The Federal Energy Regulatory Commission (Commission) is creating a new reporting requirement, FERC Form No. 715, Annual Transmission Planning and Evaluation Report, to inform potential transmission customers, State regulatory authorities, and the public of potentially available transmission capacity and known constraints as required under § 213(b) of the Federal Power Act, as added by the Energy Policy Act of 1992.

In addition to implementing the information requirements of § 213(b), the rule is intended to support the Commission's expanded responsibilities under §§ 211 and 212 of the Federal Power Act, as amended by the Energy Policy Act of 1992, and to provide information with which to analyze filings involving, or requests for, transmission services under the Federal Power Act.

The Commission is also amending Form No. FERC-714, Annual Electric Control and Planning Area Report. The conforming and other changes in Form 714 involve: (a) changing the designation of the form to read: "FERC Form No. 714"; (b) changing the

annual filing date of the form to no later than June 1 of the following year; (c) eliminating information requirements duplicating the information that the Commission will now collect in Form 715; (d) eliminating the reporting of certain information no longer needed for the Commission's regulatory purposes; and (e) modifying certain existing information requirements to improve their usefulness.

DATES : The final rule is effective [insert 30 days after publication in the Federal Register]. The information collection provisions, however, will not become effective until approved by the Office of Management and Budget. Notice of this date will be published in the Federal Register.

ADDRESSES: Office of the Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, DC 20426

FOR FURTHER INFORMATION CONTACT:

Daniel L. Larcamp (Legal Information)
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Federal Energy Regulatory Commission
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William Booth (Technical Information)
Office of Electric Power Regulation
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, DC 20426
(202) 208-0849

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in Room 3104, at 941 North Capitol Street, N.E., Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing (202) 208-1397. To access CIPS, set your communications software to use 300, 1200, or 2400 bps, full duplex, no parity, 8 data bits and 1 stop bit. CIPS can also be accessed at 9600 bps by dialing (202) 208-1781. The full text of the Final Rule will be available on CIPS for 30 days from the date of issuance. The complete text on diskette in WordPerfect format may also be purchased from the Commission's copy contractor, La Dorn Systems Corporation, also located in Room 3104, 941 North Capitol Street, N.E., Washington, D.C. 20426.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Elizabeth Anne Moler, Chair;
Vicky A. Bailey, James J. Hoecker,
William L. Massey, and Donald F. Santa, Jr.

New Reporting Requirement Implementing)
Section 213(b) of the Federal Power)
Act and Supporting Expanded Regulatory) Docket No. RM93-10-000
Responsibilities under the Energy)
Policy Act of 1992, and Conforming and)
Other Changes to Form No. FERC-714)

ORDER NO. 558

FINAL RULE

(Issued September 30, 1993)

I. INTRODUCTION

The Federal Energy Regulatory Commission (Commission) is amending Part 141 of its regulations by adding a new section 141.300 requiring that "transmitting utilities" 1/ inform potential transmission customers, State regulatory authorities, and the public of potentially available transmission capacity and known constraints as required under § 213(b) of the Federal Power Act (FPA), as added by the Energy Policy Act of 1992 (Energy Policy Act). 2/ The new regulation creates a new reporting form, FERC Form No. 715, Annual Transmission Planning and

1/ A transmitting utility is any electric utility (i.e., any person or State agency (including any municipality) which sells electric energy), qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency that owns or operates electric power transmission facilities that are used for the sale of electric energy at wholesale. See § 3(23) of the FPA, as added by the Energy Policy Act.

Evaluation Report (Form 715). In addition to implementing the requirements of § 213(b), this rule is intended to support the Commission's expanded responsibilities under §§ 211 and 212 of the FPA, as amended by Energy Policy Act, and to provide information with which to analyze filings involving, or requests for, transmission services. The Commission also is amending 18 CFR 141.51 and the associated Form No. FERC-714, Annual Electric Control and Planning Area Report (Form 714), to make conforming and other changes. 3/

A. Notice of Proposed Rulemaking

The Commission issued a Notice of Proposed Rulemaking (NOPR) on March 30, 1993. 4/ The Commission received 118 sets of comments in response to the NOPR. Commenters represent all interest groups in the electric utility industry. Commenters include: 48 investor-owned utilities; 18 municipal utilities; 12 rural electric cooperatives; 13 regional reliability councils, subregional organizations or proposed regional transmission groups (RTGs); 7 state regulatory commissions; 7 non-traditional generating entities (such as Independent Power Producers (IPPs) and Qualifying Facilities (QFs)); and 13 other parties, including

3/ Although some information required by new Form 715 is already included in Form 714, the Commission is not combining the reporting requirements into one form because the two forms differ substantially both in purpose and as to who must file them. To prevent duplication of reporting effort, the Commission is eliminating a number of schedules from Form 714.

4/ New Reporting Requirements Under the Federal Power Act and Changes to Form No. FERC-714, 58 FR 17544 (April 5, 1993); IV FERC Stats. & Regs. ¶ 32,493.

industrial customer groups, the U.S. Department of Energy (DOE) and members of the Energy and Commerce Committee of the United States House of Representatives.

B. Summary of Form 715 Requirements 5/

Starting on April 1, 1994, each transmitting utility that operates integrated transmission system facilities that are rated at or above 100 kilovolts (kV) (Respondent), will annually submit to the Commission a new reporting form, Form 715.

Form 715 requires each Respondent to:

(1) identify a contact person for inquiries regarding information in the form [Form 715, Part 1];

(2) submit in electronic form its base case power flow data 6/ if it does not participate in the development and use of regional power flow data. A Respondent that participates in the development and use of regional power flow studies must either submit in electronic form the regional or subregional base case power flow data or designate any regional or subregional organization, or any other single entity to submit in electronic form the

5/ The instructions for completing Form 715 appear in Appendix A.

6/ Base case power flows are best estimate simulations of the operations of regional transmission grids.

regional or subregional base case power flow data [Form 715, Part 2];

(3) submit transmission system maps and diagrams used by the Respondent for transmission planning [Form 715, Part 3];

(4) submit a detailed description of the transmission planning reliability criteria used to evaluate system performance for time frames and planning horizons used in regional and corporate planning [Form 715, Part 4];

(5) submit a detailed description of the Respondent's transmission planning assessment practices (including, but not limited to, how reliability criteria are applied and the steps taken in performing transmission planning studies) [Form 715, Part 5]; and

(6) submit a detailed evaluation of the Respondent's anticipated system performance as measured against its stated reliability criteria using its stated assessment practices[Form 715, Part 6].

Respondents must submit to the Commission an original and two copies in hard copy of the above items 1 through 6. Respondents must also submit to the Commission in electronic form items 1, 2, 4, 5 and 6.

Respondents must also make available expeditiously to the public, upon request, in hard copy, the above items 1 through 6. Respondents must also make available expeditiously to the public, upon request, in electronic form, items 1, 2, 4, 5 and 6.

When Respondents have designated any single entity to submit regional or subregional base case power flow data to the Commission, that entity must submit these data to the Commission in both hard copy and electronic form, as indicated immediately above. That entity must also make these data available expeditiously to the public, upon request, in both hard copy and electronic form, as indicated immediately above.

The primary authority for the collection of Form 715 data is § 213(b) of the FPA. The collection of these data also supports the Commission's expanded responsibilities under §§ 211, 212 and 213(a) of the FPA (as amended by the Energy Policy Act), and assists in rate or other regulatory proceedings. Thus, the Commission's authority for this rule is also based on the Commission's general authorities under §§ 307(a), 309 and 311 of the FPA.

C. Summary of Form 714 Revisions 7/

Changes to Form 714 involve:

(1) changing the designation of the form to read, "FERC Form No. 714," to be consistent with the designation of other Commission forms;

(2) changing the annual reporting date from May 1 to no later than June 1 of the following year (to better accommodate regional reporting of hourly demand and demand forecast data); and

(3) eliminating and modifying several existing information requirements.

The Commission is eliminating certain schedules from Form 714 because it will now collect this information in Form 715. These schedules include: Schedules VIII (Control Area Transmission Power Flow Data), XIII (Planning Area Transmission Line Data), and XV (Planning Area Transmission Maps and Diagrams). The Commission is also eliminating Schedule XIV (Hydroelectric Data) because the Commission no longer needs the information in this schedule to fulfill its responsibilities under Parts I or II of the FPA.

The Commission is also eliminating the reporting of Base Power Transfers and Incremental Transfer Capability from Schedule VI because the Commission can derive this information from data now filed in Form 715. The Commission is changing Schedule VII (Control Area System Lambda) to collect hourly system lambda data (in electronic form) for the entire year and to require a description of how transmitting utilities calculate system lambda or, for those control areas that do not use an economic dispatch algorithm, how the control area dispatches its resources.

In addition, the Commission is consolidating Schedules X (Planning Area Monthly Net Energy for Load), XI (Planning Area Summer and Winter Actual and Forecast Peak Demand and Annual Net Energy for Load), and XII (Planning Area Hourly Demand Data By Specified Week) into a requirement that Form 714 Respondents submit hourly demand data in electronic form to the Commission.

Respondents that are members of regional or sub-regional organizations may instead, however, authorize their national, regional, or subregional organizations to file hourly demand data on behalf of their member systems. If a national, regional, or subregional organization does consolidate and report Form 714 (or Form 715) information for its members, it must separately identify data for each Respondent covered by the report. The authority to collect the Form 714 information is the Commission's general information collection authorities in §§ 307(a), 309 and 311 of the FPA.

D. Major Changes in Final Rule from NOPR

The following is a list of the major changes made in the final rule from the reporting requirements proposed in the NOPR:

- Only transmitting utilities that are operators of integrated transmission system facilities that are rated at or above 100 kV must file a Form 715. The NOPR proposed submittal by operators and owners and included entities owning only radial facilities.
- A request for waiver of the requirement to file Form 715 must either: (1) indicate the entity that performs transmission planning for the entity requesting waiver, or (2) state that the entity requesting waiver does not use power flow analyses in performing transmission planning 8/

8/ The Commission expects that requiring only operators of integrated transmission facilities to file Form 715 will reduce the number of requests for waiver.

- The annual filing date for Form 715 is no later than April 1 of each year. The NOPR proposed a filing date of January 1.
- When a Respondent identifies stability as a limiting factor in its regional transmission analysis, the Respondent must, on request, make regional stability studies available to the public.
- The Commission is allowing regional organizations to charge a fee for copying the material provided to the public, and requiring that a fee schedule be included in Part 2 of Form 715.
- The Commission has eliminated Base Power Transfers and First Contingency Incremental Transfer Capability data from Schedule 5 (previously cited as Schedule VI) of Form 714. Similar information can be derived from base case power flows data that transmitting utilities now submit in Part 2 of Form 715.
- The Commission has added to Schedule 6 of Form 714 a requirement that a control area describe how it calculates its system lambda (i.e. its incremental cost of energy). 9/ Any entity that does not use an economic dispatch algorithm must describe how it dispatches its resources.
- The annual filing date for Form 714 is no later than June 1 of the following year. The current filing date is no later than May 1.

9/ A description of the development of system lambda is included in the instructions to Schedule 6, Control Area

II. PRELIMINARY MATTER

A number of commenters filed their comments after the deadline for the filing of comments in this proceeding. 10/ All of these commenters have demonstrated a substantial interest in this proceeding, and no one objects to the admission of these untimely-filed comments into the record in this proceeding. Our consideration of these comments will not unduly prolong this proceeding or prejudice any of the parties who timely filed their comments. The late-filed comments have contributed to our analysis of the issues in this proceeding. We will, therefore, accept these untimely filed comments and make them a part of the record.

Some commenters have requested the opportunity to respond to other parties' comments. Other commenters have requested that the Commission convene a technical conference.

We think that the 118 comments that we have received thoroughly explore the issues in this proceeding. We see no need for either reply comments or for a technical conference. We will, therefore, deny the requests for reply comments and for a technical conference.

III. JURISDICTION

There are two challenges to the Commission's jurisdiction to apply the rule to certain entities. Alabama Electric Cooperative (Alabama Electric) challenges the Commission's authority to apply

10/ The Commission originally designated May 20, 1993 final date for filing comments in this proceeding, but lat..

the rule to cooperatives. The Alaska Intertie Operating Committee (Alaska Committee) argues that the Commission has no power to apply the rule to the operators of Alaskan transmission facilities. We have reviewed these arguments and have concluded that, in each instance, the Commission has the authority to apply the rule to the entities.

A. Cooperatives

Section 213(b) of the FPA, as amended by the Energy Policy Act, requires the Commission to require "transmitting utilities" to provide potential transmission customers, State regulatory authorities, and the public with information concerning potentially available transmission capacity and known constraints. In the NOPR, 11/ the Commission stated that:

> A transmitting utility is any electric utility (i.e., investor-owned, cooperative, municipal or state agency), qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale. See section 3(23) of the Federal Power Act, as added by the Energy Policy Act

11/ New Reporting Requirement Under the Federal Power Act and Changes to Form No. FERC-714, 58 FR 17544 (April 5, 1993); IV FERC Stats. & Regs. ¶ 32,493.

> of 1992. [12/]

The Commission also stated that:

> [T]he Energy Policy Act gives the Commission authority to order wheeling by "transmitting utilities" as defined in the new section 3(23) of the FPA. Such entities include electric utilities (irrespective of public, cooperative or private ownership status), qualifying facilities and Federal power marketing agencies which own or operate electric power transmission facilities used for the sale of electric energy at wholesale. [13/]

Alabama Electric challenges the accuracy of the Commission's jurisdictional assertions. It notes that the Energy Policy Act does not include the word "cooperative" in its definition of "transmitting utility." Alabama Electric argues that the Commission offers no statutory support for including the term "cooperative" within the definition of "transmitting utility" or within the term "electric utility." 14/ Alabama Electric

12/ 58 FR 17544 (April 5, 1993), n.1; IV FERC Stats. & Regs. ¶ 32,493 at 32,686, n.1.

13/ 58 FR 17544, 17548 (April 5, 1993), IV FERC Stats. & Regs. ¶ 32,493 at 32,691.

14/ Alabama Electric Comments at 3

cites Salt River Project Agr. Dist. v. Federal Power Commission 15/ and Dairyland Power Cooperative 16/ for the proposition that the Commission lacks jurisdiction over cooperatives. 17/ We reject Alabama Electric's arguments. The Salt River and Dairyland cases are inapposite. These cases address whether a cooperative is a public utility as defined in the FPA. 18/ They do not address whether a cooperative is an electric utility as defined in the FPA. 19/

The terms "public utility" and "electric utility" have different meanings under the FPA. 20/ As the Commission has

15/ 391 F.2d 470 (D.C. Cir. 1968), cert. denied, 393 U.S. 857 (1968) (Salt River).

16/ Opinion No. 511, 37 FPC 12 (1967) (Dairyland).

17/ In contrast to Alabama Electric's position, North Carolina Electric Membership Corporation recognizes that "under the recently enacted Energy Act, electric cooperatives that own or operate . . . facilities used for wholesale sales could be subject to FERC jurisdiction as 'transmitting utilities' . . . regardless of their exempt status from other aspects of FERC jurisdiction." North Carolina Electric Membership Corporation Comments at 4-5.

18/ See Salt River at 472. In Dairyland, the Commission determined that non-profit cooperatives financed by the Rural Electrification Administration (REA) are not "public utilities" under the FPA, and thus do not have to comply with the Commission's reporting, accounting and rate schedule filing requirements. Salt River relied on Dairyland in finding that a specific REA-financed cooperative was "not a 'public utility' within the meaning of Parts II and III of the Federal Power Act."

19/ Salt River at 474. See also Arkansas Electric Cooperative Corp. v. Arkansas Public Service Commission, 461 U.S. 375, 381-385 (1982)(discussing Dairyland and Salt River).

20/ See Enron Power Enterprise Corp., 52 FERC ¶ 61,193 at 61,704, n.5, citing Long Lake Energy Corp., 51 FERC ¶ 61,262

noted, "[a]ll public utilities, as defined in the FPA, are electric utilities . . . . However, electric utilities include entities that are not public utilities, such as cooperative and municipal utilities." 21/ Section 3(22) of the FPA defines "electric utility" as any person, State agency, or Federal agency that sells electricity. 22/ Section 3(4) of the FPA defines "person" as an individual or corporation. 23/ Section 3(3) of the FPA defines "corporation" as, among other things, any corporation, joint-stock company, partnership, association, business trust, or any organized group of persons, whether incorporated or not. 24/ Because cooperatives fall within the definition of "corporation," they are persons that sell electricity. As such, they are "electric utilities."

When Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA), 25/ it added section 211 as well as the section 3(22) definition of electric utility to the FPA, thereby giving the Commission authority to order electric utilities not otherwise subject to its jurisdiction (i.e., not otherwise

21/ Policy Statement Regarding Regional Transmission Groups, 58 FR 41,626 (Aug. 5, 1993), III FERC Stats. & Regs. ¶ 30,975.

22/ Pub. L. No. 95-617 § 3(4), 92 Stat. 3117, (1978)(codified at 16 U.S.C. § 796(22)(1988)).

23/ 16 U.S.C. § 796(4).

24/ 16 U.S.C. § 796(3).

"public utilities") to provide transmission service. 26/ The term "transmitting utility," which the Energy Policy Act added to the FPA, and which appears in both the newly amended section 211 and the new section 213, includes the term "electric utility." The Commission, therefore, has jurisdiction under section 213(b) of the FPA, as added by the Energy Policy Act, to require cooperatives to provide information on their potentially available transmission capacity and known constraints.

B. Alaska

Alaska Committee argues that, because Alaska is not interconnected with any interstate transmission grid, Alaskan transmission facilities do not meet the Commerce Clause requirements for interstate activity. We construe its argument to mean that we should not apply the proposed reporting requirements to Alaskan utilities because to do so would be unconstitutional. 27/

26/ H.R. Rep. No. 95-1750, 95th Cong., 2d Sess. at 94-95 (1978). Prior to PURPA, the Commission had limited authority to order transmission in non-emergency situations, but only to public utilities. See FPA sections 202(b) and 207. When Congress added sections 210-212 to the FPA, it provided in section 201(b)(2) that compliance with a Commission order under sections 210 or 211 will not make an electric utility subject to the jurisdiction of the Commission for purposes other than the provisions of sections 210, 211 or 212.

27/ Alaska Committee Comments at 3-4. Alaska Committee argues that Alaskan transmission facilities do not meet the Commerce Clause requirements for interstate activity; this implies that if the Energy Policy Act does apply to these utilities, the statute is unconstitutional. In the alternative, Alaska Committee asks the Commission for an exemption, implicitly recognizing the Commission's authority to impose the reporting requirements on Alaska's transmitting utilities.

This rule requires that all transmitting utilities submit information to us. Section 3(23) of the FPA defines "transmitting utilities" as those that own or operate transmission facilities used for the sale of electric energy at wholesale. Indeed, the term "transmitting utility" (FPA section 3(23)) encompasses the term "electric utility" (FPA section 3(22)). Neither term includes any reference to a distinction between inter- and intrastate facilities. When Congress intended to make such a distinction, it did so clearly, as is evidenced by the term "wholesale transmission services" (FPA section 3(23)) which specifically refers to energy sold at wholesale in interstate commerce. 28/ Therefore, Congress intended that the information requirements of section 213(b) apply to both interstate and intrastate utilities.

Moreover, there is little doubt that Congress may regulate intrastate utilities. Congress may regulate an intrastate activity when that activity is part of a national activity that Congress has chosen to regulate under its interstate commerce power. When it enacted the Energy Policy Act, Congress's purpose was national in scope. 29/ It intended to encourage a competitive bulk power market, to promote increased efficiency

28/ FPA section 3(24) defines wholesale transmission services as the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.

29/ Congress's aim was nothing less than a "comprehensive national energy policy . . . ." H.R. Rep. No. 102-474, 102nd Cong. 2nd Sess., pt. 1 at 132 (1992)

and reduce the cost of electric energy. 30/ Information regarding transmission availability and known constraints is essential to market-oriented pricing. And Congress has a legitimate interest in using market forces to aid in producing an abundant supply of electric energy at reasonable prices. The transmission information requirements are, therefore, reasonably adapted to a constitutional end, as the case law requires. 31/ Since the effects of electricity are all-pervasive in our society, Congress was well within its interstate commerce authority in applying its transmission information requirements to transmitting utilities that are not connected to an interstate transmission grid. 32/ The Commission has found jurisdiction

30/ H R. Rep. No. 102-474, 102nd Cong. 2nd Sess., pt. 1 at 132-138 (1992). Congress sought "to use the market rather than government regulation wherever possible both to advance energy security goals and to protect consumers." Id. at 133. It hoped that "additional competition in [the] wholesale electricity power market . . . [would] improve the efficiency of the electric utility industry and secure the lowest possible costs for consumers." Id. at 138.

31/ See Presault v. Interstate Commerce Commission, 494 U.S. 1, 17 (1989); Hodel v. Virginia Surface Mining & Reclamation Assn., Inc., 452 U.S. 264 (1981); Hodel v. Indiana, 452 U.S. 314, 323-324 (1981); FERC v. Mississippi, 456 U.S. 472 (1981).

32/ See, e.g., Heart of Atlanta Motel v. United States, 379 U.S. 241 (1964); Katzenbach v. McClung, 379 U.S. 294 (1964); Wickard v. Filburn, 317 U.S. 111 at 125 (1942)(Congress may reach local activity if the activity "exerts a substantial economic effect on interstate commerce"); cf. Arizona Public Service Co. v. Snead, 441 U.S. 141 (1979)(New Mexico's energy tax found to be an impermissible burden on interstate commerce).

in analogous circumstances. 33/

IV. OBJECTIVES OF FORM 715

A. Implementation Alternatives

In addressing how best to implement the requirements of § 213(b), the Commission stated in the NOI'R that, based on its experience, "it is not practical to provide a simple measure of transmission availability that would cover all potential transmission service requests." 34/ The Commission stated that the better approach to providing meaningful information to potential transmission customers is to require access to "the fundamental information used and assumptions made by the transmitting utility to perform its planning and operating studies" 35/ so that these potential customers "can perform their own studies and reach their own conclusions." 36/

One commenter states that the Commission's interpretation is the only practical approach. 37/ Other commenters state that the Commission's approach is consistent with Congressional intent

33/ See Central Power and Light Company, 8 FERC ¶ 61,065, modified and reh'g denied, 9 FERC ¶ 61,011 (1979), reh'g denied, 10 FERC ¶ 61,131 (1980); Kalaeloa Partners, L.P., 48 FERC ¶ 61,173 (1989).

34/ 58 FR 17548 (April 5, 1993); IV FERC Stats. & Regs., Proposed Regulations ¶ 32,493 at 32,692.

35/ Id.

36/ 58 FR 17548 (April 5, 1993); IV FERC Stats. & Regs. at 32,693.

37/ See Pennsylvania-New Jersey-Maryland Interconnecti

in establishing § 213(b). 38/ On the other hand, some commenters do not support the Commission's approach, stating that it is unnecessary, burdensome, wasteful, unreasonable, will not provide useful or meaningful information, or exceeds the intent of Congress. 39/

Seven commenters believe that potential transmission customers would not be able to use the requested information to do their own analyses. 40/ One of the commenters states that "if potential users want to know if a transmission system can accommodate additional transfers, they will have to ask the owners and operators of that generation and transmission system." 41/ A few commenters also question the value of collecting this information in light of alleged national security

38/ See, e.g., American Iron and Steel Institute, et al. Comments at 3; Indiana Utility Regulatory Commission Comments at 2; U.S. Department of Energy (DOE) Comments at 1; Electric Generating Association Comments at 1; Texas Utilities Comments at 1; National Association of Regulatory Utility Commissioners (NARUC) Comments at 3; Pacific Gas & Electric Comments at 3.

39/ See, e g., Centerior Comments at 1; Northern States Power Comments at 2; Central Louisiana Electric Comments at 3; Large Public Power Council Comments at 5.

40/ See Central Louisiana Electric Comments at 3; Wisconsin Power and Light Comments at 2; North American Electric Reliability Council (NERC) Comments at 2; Northern States Power Comments at 6; South Carolina Electric & Gas Comments at 1; Virginia-Carolinas Reliability Group Comments at 3-4; and Central & Southwest Comments at 2.

41/ NERC Comments at 2.

concerns. 42/ Additionally, several commenters state that the information to be collected is not sufficient to analyze transmission capability because stability is the limiting factor in their areas. These commenters argue that more detailed and specific data and analyses are needed to evaluate transmission capability. 43/

These commenters propose a number of alternatives, such as: (1) allowing transmitting utilities to provide the information when requested, (2) relying on the transmitting utility to perform any studies, perhaps jointly with the requester, (3) requiring that transmitting utilities provide only summary information, such as regional assessments, DOE OE-411 reports or transfer capability data, and (4) encouraging working through regional reliability councils or regional transmission groups (RTGs).

The Commission concludes that none of the proposed alternatives satisfies the requirements of § 213(b). Requiring transmitting utilities to make information available only on request or relying on a transmitting utility to perform the studies is inconsistent with the annual collection and public availability requirements of § 213(b). Furthermore, a large number of commenters, representing the entire spectrum of

42/ See, e.g., Commonwealth Edison, et al. Comments at 2-3; Central Illinois Public Service Comments at 6. This issue is addressed separately in Section V.B, below.

43/ See, e.g , Public Generating Pool Comments at 3; Montana-Dakota Utilities Comments at 2; San Diego Gas & Electric Comments at 2; Large Public Power Council Comments at 5

interests, state that the information as defined in this rule will be useful to potential customers for screening analyses of transmission capability. 44/

The Commission has concluded that there is, at present, no simpler way to satisfy the requirements of § 213(b). 45/ Regional reliability council assessments (such as NERC summer and winter assessments that contain interregional transfer capabilities for those periods or DOE OE-411 reports) are too general to provide useful information to potential transmission customers for meaningful analysis regarding specific inquiries. Similarly, regional operating studies -- which estimate the ability to transfer energy between control areas or regions (such as the East Central Area Reliability Coordination Agreement's (ECAR) summer and winter assessment of transmission system performance) -- provide little, if any, information regarding the availability of transmission capacity within or across a control

44/ See, e.g., NARUC Comments at 5-7; DOE Comments at 3; California Energy Commission Comments at 1; National Rural Electric Cooperative Association, et al. Comments at 1-2; National Independent Energy Producers Comments at 3; Indiana Utility Regulatory Commission Comments at 4; American Public Power Association (APPA) Comments at 1-3; Western Systems Coordinating Council Comments at 1-4; Duke Power Comments at 3; Edison Electric Institute (EEI) Comments at 7; Institute of Electrical and Electronic Engineers (IEEE) Comments at 2.

45/ The Tennessee Valley Authority (TVA) states that it "would be willing to work with the Commission on ways to develop a system of reporting transmission capacity that would both minimize the reporting burden and provide a realistic measure of available capacity and known constraints." TVA Commments at 2. The Commission supports and encourages efforts to identify more efficient and less costly means to develop data required by § 213(b).

area or region. In addition, reported transfer capability data do not provide sufficient information to evaluate or to screen for either alternative generation sites or for the effects of alternative bulk power purchases and sales on the transmission system. 46/

A number of commenters disagree with the Commission's objective of providing data to potential transmission customers so that customers can perform their own studies and reach their own conclusions. These commenters state that meaningful planning studies can result from joint studies done from a regional perspective. The commenters urge that the Commission discourage potential customers from performing their own studies and instead encourage them to work through regional organizations such as RTGs to develop transmission capacity studies. 47/

The Commission agrees with the commenters that RTGs could be good vehicles for satisfying the intent of § 213(b) and encourages parties to work through regional transmission organizations to develop the data required by this rule. 48/

46/ See, e.g., Southwest Power Pool Comments at 4; Utah Associated Municipal Power Systems Comments at 4-7. A transmitting utility may, however, use the results of regional assessments and transfer capability studies, in part, to develop the narrative description of the transmitting utility's evaluation of its transmission performance, which Part 6 of Form 715 requires.

47/ See, e.g., Southwest Power Pool Comments at 3; NERC Comments at 2; South Carolina Electric & Gas Comments at 1; Virginia-Carolinas Reliability Group Comments at 3-4.

48/ The Commission recently issued a Policy Statement encouraging the development of RTGs. Policy Statement

(continued...)

However, RTGs simply do not exist at the present time and thus are not available to help us meet the requirements of § 213(b). In addition, once RTGs do exist, not all entities may see a need to work through a regional organization. Some entities, such as Exempt Wholesale Generators (EWGs) or Qualifying Facilities (QFs), with multiple facilities across the Nation, may not wish to join each regional group throughout the country, but nevertheless are interested in the ability to perform screening studies. The information requirements of this rule allow potential transmission users to judge for themselves the value of either working through regional organizations or doing screening studies on their own.

B. Objectives in Gathering Form 715 Information

Several commenters ask the Commission to state that it intends transmitting utilities and potential transmission customers to use Form 715 information only for screening studies. They also ask the Commission to recognize that a transmitting utility can only assess the actual availability of transmission capacity when presented with a specific request for transmission service under § 213(a). 49/ Some commenters allege that the Commission is confusing the requirements of § 213(b) with those

48/(...continued)
Regarding Regional Transmission Groups, 58 FR 41626 (Aug. 5, 1993); 64 FERC ¶ 61,138 (1993). As yet, however, no RTG has been approved.

49/ See, e.g., Wisconsin Public Service Comments at 1-2; Southern Company Services Comments at 13-14; Pennsylvania Power & Light Comments at 2-3.

of § 213(a). 50/

The Form 715 reporting requirement serves two purposes. First, Form 715 will provide a potential transmission customer with sufficient information to perform a screening analysis (i.e., a preliminary study of the availability of transmission capacity for the region of interest) to determine the likely response by a transmitting utility should the customer make a request for transmission service. With this information in hand, the potential transmission user can make broad estimates of the likely transmission costs of a potential transaction. The availability of such information should reduce the instances when a transmitting utility denies a request for transmission service because transmission capacity is not available or because its cost is too high.

Second, Form 715 will provide potential transmission customers, State regulatory authorities, and the public with the specific procedures that a transmitting utility will follow when determining available transmission capacity in response to a request for service. The information in Parts 3 through 6 of Form 715 will enhance the understanding of how an individual transmitting utility performs transmission planning studies that it will need to respond to a transmission service request.

Some commenters allege that there is an inconsistency between the general nature of the regional power flow base cases

50/ See, e.g., American Electric Power Comments at 2; Duke Power Comments at 4-21.

required in Part 2 of Form 715 and the individual detail required in Parts 3 through 6 of Form 715. 51/ The different requirements of these Parts are intentional; data from the various Parts complement each other. 52/ Regional power flow base cases typically do not include certain lower voltage transmission lines within the region, while transmission planning data, criteria and procedures that transmitting utilities use typically consider all lower voltage transmission lines.

Furthermore, Form 715 will inform a potential customer of the current utility practices that may be relevant to a specific request for transmission service. The annual reporting of Form 715 also will ensure identification of significant changes in data, criteria or procedures used to analyze individual requests. The availability of Form 715 information should also help to ensure the accuracy and consistency of transmission planning information and assist potential customers in corroborating the validity of transmitting utility responses to requests for service. Similarly, the availability of a utility's transmission

51/ See, e.g., Midwest Power Systems Comments at 2; Municipal Energy Agency of Nebraska Comments at 6; NERC Comments at 9; Pacific Gas & Electric Comments at 4.

52/ The Commission notes that advances in computing capability are allowing regional power flow analyses to reflect more individual utility detail. Future regional models are likely to include much more individual utility data as utilities attempt to reduce the number of sets of base cases they must maintain on their own and the amount of additional individual data they must input when using regional base cases as the basis for performing their own analyses. See, e.g., Southwest Power Pool Comments at 2; APPA Comments at 18; Transmission Access Policy Study Group Comments at 11.

planning information will help potential transmission customers make better "good faith" requests and better understand the transmitting utility's response.

Although the level of detail in Parts 3 through 6 of Form 715 may, in some cases, exceed that necessary to understand and to use the regional data furnished under Part 2 of Form 715, the Commission finds that the need to understand the entire process of determining available transmission capacity and constraints on individual systems warrants the filing of this information. The Commission intends to make publicly available information that reflects, to the fullest extent possible, utilities' current planning processes. These criteria and procedures may change in light of the open transmission access environment that is now evolving. Changes in the planning process may also occur as a result of organizational developments, such as the formation of RTGs. Ensuring that current information is available regarding available transmission capacity is consistent with our statutory responsibilities and Congressional intent in enacting the relevant sections of the Energy Policy Act, i.e., those modifying §§ 211 and 212 and adding § 213 to the FPA.

C. Use of Existing Information

The NOPR stated that the proposed Form 715 reporting requirement would rely in large part on existing information. Most commenters generally agree. 53/ Part 2 (regional power

53/ See, e.g., American Electric Power Comments at 3; NERC Comments at 2; Western Systems Coordination Council Comments (continued...)

flow base cases) and Part 3 (utility maps and diagrams) of Form 715 do not require the development of new information. Transmitting utilities currently develop and use these data in the course of their utility business.

Parts 4 and 5 (criteria and planning procedures) of Form 715 require a description of a transmitting utility's planning reliability criteria and planning assessment procedures. Commenters indicate, however, that the degree of documentation of procedures varies among companies. For example, many utilities state that they make numerous engineering judgments in the course of performing transmission studies. Because these judgments are based on the planner's experience, they are not generally documented in any systematic fashion.

Commenters also raise concerns regarding the meaning of certain portions of the instructions of Parts 4 and 5 of Form 715. They interpret certain phrases contained in these Parts, such as "in totality" and "reasonably replicate," as requiring an unreasonable or impractical amount of detail. 54/

The Commission is not requiring the documentation of the institutional knowledge of transmitting utilities' planning

53/(...continued)
at 2; Associated Electric Cooperative Comments at 3; Municipal Electric Authority of Georgia Comments at 3; NARUC Comments at 6.

54/ See, e.g., American Electric Power Comments at 6-7; NERC Comments at 10; Entergy Services Comments at 4-5; Union Electric Comments at 8; Associated Electric Cooperative Comments at 4-5; Duke Power Comments at 3-4; Allegheny Power Service Comments at 2-4; Pacific Gas & Electric Comments at 9.

engineers. The Commission's intention is that transmitting utilities file the substantive criteria and planning procedures that they follow in the normal course of business. The information that transmitting utilities will file in Form 715 should help requesters to perform preliminary screening analyses and to better understand the process of determining available transmission capacity. With such knowledge, requesters can better anticipate the response to an inquiry regarding potential transmission service. In the final rule, the Commission has modified the instructions of Parts 4 and 5 to clarify this point. It has also removed the terms "in totality" and "reasonably replicate" to ensure that Form 715 will not require an unreasonable amount of detail.

Because most criteria and procedures required by Parts 4 and 5 should already be identified and documented by utilities, the Commission does not expect that new information will have to be developed. If utilities have not identified or documented some of their criteria and procedures, they will have to add this to their existing materials in order to satisfy the initial reporting requirements for Parts 4 and 5. In subsequent years, however, only changed criteria and procedures are required to be filed.

The evaluation of transmission system performance requirement of Part 6 of Form 715 does require data that transmitting utilities do not currently develop in the normal course of business. This evaluation requires new data because:

(1) the analysis is to include information that encompasses future periods that generally are longer than the periods covered by operating studies utilities currently perform; and (2) similar evaluations are not collected or cannot be derived from existing information requirements. Without these data, neither the Commission nor potential transmission users can estimate potentially available transmission capacity and known constraints. Consequently, the rule will not satisfy the statutory mandate that transmission capacity and known constraints be made available without the development of this information.

V. DISCUSSION OF SPECIFIC ISSUES

A. Reporting Burden

The estimate of the annual reporting burden for Form 715 is 200 hours per response. In the NOPR, the Commission estimated the reporting burden to be 100 hours per response. Many commenters indicate that if the Commission requires the reporting of only existing information and a narrative description for Part 6, the 100 hours per response estimate is reasonable after the first year. 55/ Other commenters suggest that the burden is greater than 100 hours, with estimates generally ranging from 250

55/ See, e.g., EEI Comments at 20-21; Oglethorpe Power Corporation Comments at 9; Allegheny Power Service Comments at 4-5; Pacific Gas & Electric Comments at 10-11; Mid-Continent Area Power Pool Comments at 3; Minnesota Power & Light Comments at 4; Pennsylvania Power & Light Comments at 3; TVA Comments at 1.

to 600 hours. 56/ After consideration of the comments, the Commission concludes that 200 hours is a more accurate reflection of the average reporting burden per response for Form 715. The estimated number of Form 715 respondents is 200; thus, the resulting total annual reporting burden is 40,000 hours.

The Commission estimates that the annual reporting burden for the revised Form 714 will decline from 86 to 50 hours per response. Two commenters claim that the Commission has underestimated the reporting burden associated with changes to Form 714. 57/ After further consideration, the Commission retains the burden estimate of 50 hours per response for Form 714. The estimated number of Form 714 Respondents is 250; thus, the resulting total annual reporting burden is 12,500 hours.

These estimates include time for reviewing instructions, gathering and maintaining the data, and reviewing the collection of information. Comments regarding these burden estimates or any other aspect of this collection of information, including suggestions for reducing the reporting burden, should be filed at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, DC 20426 [Attention: Michael Miller,

56/ See, e.g., Midwest Power Systems Comments at 7-8; Southwestern Public Service Comments at 3; Associated Electric Cooperative Comments at 6; Houston Lighting & Power Comments at 4; Northeast Utilities Comments at 5; Boston Edison Comments at 3; Central & Southwest Comments at 1. At the extreme, one commenter estimates that thousands of hours would be required to meet the new data requirements. Northern States Power Comments at 9-10.

57/ See Pacific Gas & Electric Comments at 10; and Southwest Regional Transmission Association Comments at 16.

Information Services Division] and sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission].

B. National Security Concerns

A large number of commenters indicate that the filing of Form 715 data raises national security concerns. 58/ Several commenters note that although much of the information either is currently available from various sources or could be developed, Form 715 combines the information into one source and thus makes it more readily available to those who might misuse it. 59/ To mitigate concerns regarding national security, commenters suggest that the Commission: (1) consult with NERC and other organizations that monitor terrorist activity before issuing a final rule; 60/ (2) place restrictions on access to Form 715 information, such as screening requesters, or requiring that the

58/ See, e.g., NERC Comments at 1-3; New England Power Pool Comments at 3; Commonwealth Edison, et al. Comments at 3; Mid-America Interconnected Network Comments at 2; Pennsylvania-New Jersey-Maryland Interconnection Comments at 4-5; San Diego Gas & Electric Comments at 5-6; Central Maine Power Comments at 3; South Carolina Electric & Gas Comments at 2; New England Power Service Comments at 3-5; Central Illinois Public Service Comments at 2; Virginia-Carolinas Reliability Group Comments at 3.

59/ See, e g., Wisconsin Pubic Service Comments at 2; Southern Company Comments at 20; Commonwealth Edison, et al. Comments at 12; Central Illinois Public Service Comments at 6; New England Power Service Comments at 4.

60/ See, e.g., Mid-American Interconnected Network Comments at 2; Pennsylvania-New Jersey-Maryland Interconnection Comments at 5; Southern Company Comments at 20.

information be made confidential; 61/ or (3) require that requesters state the intended use of the information. 62/ Other commenters claim that some commenters may be raising national security issues in an attempt to thwart the establishment of the reporting requirement. 63/

A number of commenters object to reporting "a list of critical facilities." 64/ These commenters indicate that the industry has specifically avoided creating such a list due to national security concerns. NERC suggests that rather than requiring the reporting of a list of critical facilities, the Commission should ask Respondents to indicate the various contingencies against which the utility typically tests in applying its reliability criteria. 65/

61/ See, e.g., Midwest Power Systems Comments at 7; South Carolina Electric & Gas Comments at 2; Commonwealth Edison, et al. Comments at 13; Central Illinois Public Service Comments at 7; Duke Power Comments at 29; Allegheny Power Service Comments at 3; Dayton Power & Light Comments at 1.

62/ See, e.g., Midwest Power Systems Comments at 7; Cajun Electric Power Cooperative Comments at 5; Transmission Access Policy Study Group Comments at 17.

63/ See, e.g., Sacramento Municipal Utility District Comments at 6-7; National Independent Energy Producers Comments at 3; Transmission Access Policy Study Group Comments at 16-17; Members of the House of Representatives Energy and Commerce Committee Comments at 1-3.

64/ 58 FR 17552 (April 5, 1993); IV FERC Stats. & Regs. ¶ 32,493 at 32,699. See, e.g., Wisconsin Public Service Comments at 2; San Diego Gas & Electric Comments at 5-6; South Carolina Electric & Gas Comments at 2; Virginia-Carolinas Reliability Group Comments at 3; Duke Power Comments at 29; Cajun Electric Power Cooperative Comments at 5; Houston Lighting & Power Comments at 4; TVA Comments at 1.

65/ See NERC Comments at 5.

The Commission agrees with this suggestion. In the final rule, the Commission has revised Part 5 of Form 715 to require the identification of contingencies that a Respondent typically uses to perform transmission assessments. The Commission does not intend that utilities compile lists of sensitive facilities.

Entities that are concerned that someone may use Form 715 information improperly may, when receiving requests for the information, require the identity of requesters (e.g., organization name, contact person, verifiable address) as a prerequisite for disclosure of information. The Southwest Power Pool points out that keeping a record of the name and address of a requester will have an added benefit of allowing transmitting utilities to inform requesters of errors in the information provided. 66/ The final rule, however, does not require requesters to state the intended use of the information. Such a requirement would exceed that necessary to reasonably administer the statutory requirements of § 213(b) while doing little to address national security concerns. Given the clear Congressional intent to make this information available to the public, the Commission will not treat Form 715 information as confidential or limit public access to it. 67/

66/ See Southwest Power Pool Comments at 4.

67/ NERC supports this position; it states:

> Our investigation and discussions showed a misconception among security experts regarding how publicly and routinely disclosing transmission line loadings could increase the vulnerability of (continued...)

C. Form 714 Changes

1. Elimination of Redundant or Unnecessary Data

As part of the implementation of § 213(b), the Commission proposed certain changes to Form 714. The changes involve eliminating and modifying several existing information requirements. The Commission is eliminating four Schedules of Form 714: Schedule VIII, Control Area Transmission Power Flow Data; Schedule XIII, Planning Area Transmission Line Data; Schedule XIV, Hydroelectric Data; and Schedule XV, Planning Area Transmission Maps and Diagrams. The Commission is eliminating Schedules VIII, XIII, and XV because the Commission will now collect this information through Form 715. The Commission is eliminating Schedule XIV because the Commission no longer needs this information to fulfill the Commission's regulatory responsibilities under Parts I and II of the FPA. Most commenters support these changes. 68/

Some commenters ask the Commission to eliminate the requirement to report the Base Power Transfers and the First

67/(...continued)

> transmission facilities to sabotage and terrorism. These experts now have a better understanding of how electric transmission systems work, the nature of the data requested, and their concerns have been ameliorated. These agencies have agreed to defer to NERC to speak to the national security concerns. NERC only asks that the word "critical" in "critical facilities" be dropped or changed. NERC Comments at 6.

68/ See, e.g., EEI Comments at 21-22; Dayton Power and Light Comments at 4; Northeast Utilities Comments at 5-6; PSI Energy Comments at 7; Union Electric Comments at 12-13.

Contingency Incremental Transfer Capability (FCITC) data in Part I, Schedule VI of Form 714. They contend that these data are redundant because similar information can be derived from the base case power flow data submitted in Part 2 of Form 715. 69/ The Commission agrees. In the final rule, the Commission has eliminated from Form 714 the requirement to report Base Power Transfers and FCITC data.

2. System Lambda Data

The proposed rule would revise the reporting format for Schedule VII, Control Area System Lambda, to require reporting in electronic form of hourly system lambda data. 70/ Sixty-nine commenters address the issue of collecting system lambda data.

In the NOPR, the Commission stated that the purpose of collecting system lambda data together with other Form 714 data is "to permit the replication of production cost simulations...." 71/ Numerous commenters indicate that system lambda cannot serve this purpose because system lambda is typically an "output" of production cost studies, not an input

69/ See e.g., EEI Comments at 22; Central & Southwest Comments at 20; Commonwealth Edison, et al. Comments at 27; Midwest Power Systems Comments at 11.

70/ Respondents currently are required to report only certain statistics, i.e., monthly highs, lows, and averages for system lambda. Hourly system lambda are necessary in order to calculate these statistics.

71/ 58 FR 17545 (April 5, 1993); IV FERC Stats. & Regs. ¶ 32,493 at 32,687.

data requirement. 72/ They are correct; a more accurate statement is that system lambda data can assist in validating results of production cost simulations.

The Commission stated in the NOPR that system lambda information may "be useful to prospective generators in deciding where to locate." 73/ Several commenters disagree. 74/ However, they do not rebut the observation that system lambda data will help identify areas where introduction of more efficient generation could lower energy costs.

Many commenters claim system lambda data are proprietary and competitively sensitive information. 75/ Their concern is that making current system lambda data available to others may weaken a utility's competitive position. The system lambda data collected, however, are historical, i.e., for the prior year.

72/ See, e.g., NERC Comments at 11; Electric Power Consultants Comments at 1; APPA Comments at 16; PSI Energy Comments at 7; Montana-Dakota Utilities Comments at 3; National Rural Electric Cooperative Association, et al. Comments at 9-10; Cajun Electric Power Cooperative Comments at 6-7; Power Computer Applications Comments at 2.

73/ 58 FR at 17545; IV FERC Stats. & Regs. ¶ 32,493 at 32,687.

74/ See, e.g., Southern Company Services Comments at 22; Atlantic City Electric Comments at 7; Northern States Power Comments at 16.

75/ See, e.g., Otter Tail Power Comments at 3; American Electric Power Comments at 8; Wisconsin Power & Light Comments at 1-3; Oklahoma Gas & Electric Comments at 4; Public Service Electric & Gas Comments at 5-6; Southwestern Public Service Comments at 7; Florida Power & Light Comments at 2; Central & Southwest Comments at 3; National Rural Electric Cooperative Association, et al. Comments at 9-10; Associated Electric Cooperative Comments at 2-3; Central Illinois Public Service Comments at 13-15; Dayton Power & Light Comments at 1-2.

Historical hourly system lambda data do not necessarily provide a good projection of the future. As NERC states in its comments:

> The timeliness of the data is the key. Having lambda available to the public in real-time may be anticompetitive. [76/]

Even commenters arguing for non-disclosure of system lambda data agree that one cannot project future generation costs on the basis of historical hourly system lambda data. 77/ Furthermore, a number of commenters, most of which are utilities with their own control areas, indicate a willingness to provide hourly system lambda data and do not consider such data proprietary. 78/ Moreover, fifteen control areas have submitted hourly system lambda data since 1990. Although not required to, these entities have done so, presumably because it is less burdensome than providing the monthly statistics.

Because the system lambda data reported: (1) are historical, (2) cannot be used to derive unit specific cost data, and (3) are currently provided by a number of entities, the information is neither confidential nor proprietary.

Many commenters state that it is unfair to provide system lambda information to their competitors unless the Commission

76/ NERC Comments at 12.

77/ See, e.g., Wisconsin Power and Light Comments at 1; Southern Company Services Comments at 23; EEI Comments at 26.

78/ See, e.g., LG&E Energy Comments at 2; Consumers Power Comments at 2-3; Duke Power Comments at 33; Duquesne Light Comments at 7-8; Pacific Gas & Electric Comments at 6-7.

also requires competitors, especially non-traditional utility generators, to report this information. 79/ Some commenters confuse system lambda data with unit-specific cost information. System lambda data do not provide incremental production cost information for individual units. The data collection is intended to show hourly system information, not unit data. System lambda data are a product of economically dispatching thermal generating resources to follow load within a control area. 80/ Individual unit data are not system lambda data and are of limited value for purposes of this rule. Although a number of commenters ask the Commission to require collection of unit-specific information (either to allow for replication of production cost simulations 81/ or to allow redispatch of

79/ See, e.g., Midwest Power Systems Comments at 4; Virginia Electric and Power Comments at 3; Union Electric Comments at 13-14; San Diego Gas & Electric Comments at 7-9; Northern States Power Comments at 14-16; Florida Power & Light Comments at 2; South Carolina Electric & Gas Comments at 2; Consumers Power Comments at 2-3; Central & Southwest Comments at 3; Texas-New Mexico Power Comments at 16-17; Duke Power Comments at 33; Houston Lighting & Power Comments at 2-3; Allegheny Power Service Comments at 5; Northeast Utilities Comments at 5-6; Wisconsin Power & Light Comments at 1-3; Centerior Energy Comments at 5; Minnesota Power & Light Comments at 4; Pennsylvania-New Jersey-Maryland Interconnection Comments at 13-15; Oglethorpe Power Corporation Comments at 9-11; TVA Comments at 2.

80/ Units owned by others, including QFs and other non-traditional generators, can affect the dispatch of these resources and can affect the net of control area purchases and sales.

81/ See, e.g., APPA Comments at 16-17; Allegheny Electric Cooperative, et al. Comments at 52-58; National Independent Energy Producers Comments at 4-6; National Power Comments at 5-6.

units in power flow studies 82/), the Commission finds that it does not need such information for purposes of § 213(b) (i.e., performing screening analyses) or for other Commission regulatory responsibilities. 83/ Therefore, the Commission will not require individual-unit data. Consequently, the Commission will not require entities such as QFs and other non-traditional generators, that own only a single unit, to submit system lambda information data.

Many commenters question whether the Commission is justifying changes to system lambda reporting under § 213(b) 84/ or whether it intends to use the data to identify transmission availability or constraints. 85/ These

82/ See, e.g., Electric Power Consultants Comments at 1; Duquesne Light Comments at 2; Oglethorpe Power Corporation Comments at 5.

83/ In fact, production cost simulations may be just as reliable a method for competitors to use for estimating (projecting) a utility's current (future) incremental costs. Competitors can perform these studies using publicly available information (such as the monthly delivered cost of fuel delivered to generating plants reported in FERC Form No. 423, plant operation and maintenance costs and purchases and sales data reported in FERC Form No. 1, and actual and typical heat rate data reported by the Energy Information Administration in EIA Form 860 and Electric Power Research Institute Technical Assessment Guides, respectively).

84/ See, e.g., Midwest Power Systems Comments at 4; American Electric Power Comments at 8; Minnesota Power & Light Comments at 4; Northern States Power Comments at 14-16; Oglethorpe Power Corporation Comments at 9-11; New England Power Pool Comments at 3; Northeast Utilities Comments at 5-6; Houston Power & Light Comments at 2-3.

85/ See, e.g., Public Generating Pool Comments at 3; Oklahoma Gas & Electric Comments at 4; Centerior Energy Comments at 5; Orlando Utilities Commission Comments at 2; Southwestern (continued...)

commenters misconstrue both the purpose of the proposed rule and the authority under which the Commission is requiring production of hourly system lambda data. Changes to the Form 714 schedules are necessary to avoid duplication of the information requirements established in new Form 715, which implements § 213(b). The Commission is not collecting Form 714 data, including the reporting of hourly system lambda, for § 213(b) purposes.

The proposed rules are designed in part to enable the Commission to better monitor the wholesale electric power market in an era of increasing market competition. 86/ The Commission must monitor wholesale power markets to carry out its regulatory responsibilities in an era of increasing competition in the electric utility industry, especially in the generation sector. As many commenters point out, 87/ hourly system lambda data will contribute to the body of knowledge necessary to understand the changing wholesale electric market. One commenter states that hourly system lambda are a minimum basis for testing

85/(...continued)
Public Service Comments at 7; Florida Power & Light Comments at 2; EEI Comments at 23-27; Associated Electric Cooperative Comments at 2-3; Commonwealth Edison, et al. Comments at 26-29; Northeast Utilities Comments at 5-6.

86/ See New Reporting Requirements Under the Federal Power Act and Changes to Form No. FERC-714, 58 FR 17544 (April 5, 1993); IV FERC Stats. & Regs. ¶ 32,493 at 32,687-88.

87/ See, e.g., Indiana Utility Regulatory Commission Comments at 4-6; DOE Comments at 11; Duquesne Light Comments at 7-8; American Iron & Steel Institute, et al. Comments at 13-15.

whether market forces discipline the price for generation resources. 88/

The Commission can better monitor markets by comparing, on an hour-by-hour basis, the system lambda of control areas within a region or adjacent regions. Although system lambda comparisons may be only a rough measure of market performance, they nevertheless serve as a preliminary indicator of market problems. Significant differences in hourly system lambda indicate that trade possibilities have not been exhausted. This market failure could be due to transmission capacity constraints or other reasons, such as inadequate information availability or market power. As the Commission relies more on market forces to discipline prices, the performance of wholesale markets takes on added importance. These comparisons also will assist the Commission in carrying out other regulatory responsibilities, such as power pooling studies pursuant to § 205(b) of PURPA and analyses of electric bulk power transfers and system interconnected operations.

Some commenters state that the current collection of monthly statistics on system lambda is adequate for monitoring the market. 89/ Adequate comparisons cannot be made from monthly statistics. Other commenters contend that system lambda data are

88/ See Transmission Access Policy Study Group Comments at 15.

89/ See, e.g., Pennsylvania-New Jersey-Maryland Interconnection Comments at 13-15; Union Electric Comments at 13-14; Central & Southwest Comments at 3; Commonwealth Edison, et al. Comments at 25-26; Central Illinois Public Service Comments at 13-15.

of little use for monitoring the market. They argue that because various utilities calculate system lambda differently, comparison of system lambda is of questionable value. 90/ Commenters also claim that system lambda may be distorted by operational requirements or the mix of thermal and hydroelectric generation. 91/

The Commission acknowledges that different utilities use different methods to calculate system lambda. These commenters, however, do not show that this limitation seriously undermines the usefulness of the data as a preliminary indicator of market performance. In addition, most control areas calculate system lambda, so there is a common criterion for comparison.

The final rule requires that control areas using an economic dispatch algorithm must document how they calculate system lambda. Control areas that do not use an economic dispatch algorithm must describe how they dispatch their resources. By requiring the documentation of system lambda development, the Commission can identify significant differences in methodologies

90/ See, e.g., Public Service Commission of Wisconsin Comments at 6; PSI Energy Comments at 7-8; Minnesota Power & Light Comments at 4; San Diego Gas & Electric Comments at 7-9; Southwestern Public Service Comments at 7; New England Power Pool Comments at 3; Houston Power & Light Comments at 2-3; Allegheny Power Service Comments at 5; Multinational Business Services Comments at 1.

91/ See, e.g., APPA Comments at 17; City of Colorado Springs Comments at 6; Entergy Services Comments at 6; Western Group Considering Formation of RTG(s) Comments at 8; Puget Sound Power & Light Comments at 4-6; Cajun Electric Power Cooperative Comments at 6-7; Power Computer Applications Comments at 2.

that may affect the level of system lambda and that may make direct comparison with other data less meaningful.

The Commission's authority to collect hourly system lambda data derives from several provisions of the FPA. First, section 304 authorizes the Commission to require every public utility to make adequate provision for determining the current cost of generating electric energy and to report that cost to the Commission. 92/ Second, section 309 of the FPA gives the Commission power to perform any and all acts and to prescribe such rules and regulations as it finds necessary to carry out the provisions of the Act. 93/ Among other things, the Commission may prescribe the reports to be filed with the Commission, and the information that they shall contain. 94/ Third, so that the Commission can secure information upon which to recommend legislation, section 311 of the FPA authorizes the Commission to conduct investigations regarding the generation, transmission, distribution, and sale of electric energy, however produced,

92/ 16 U.S.C. 825(c).

93/ 16 U.S.C. 825h.

94/ 16 U.S.C. 825h. Section 309 authorizes the Commission "to use means of regulation not spelled out in detail, provided . . . [the Commission's] action conforms with the purposes and policies of Congress and does not contravene any terms of the Act." Niagara Mohawk Power Corp. v. Federal Power Commission, 379 F.2d 153, 158 (D.C. Cir. 1967). Although section 309 does not confer additional power on the Commission, it does augment those powers that Congress has conferred upon it. New England Power Co. v. Federal Power Commission, 467 F.2d 425 (D.C. Cir. 1972), aff'd 415 U.S. 345 (1973). Here, the Commission is collecting information that sections 304 and 311 of the FPA authorize it to collect.

throughout the United States and its possessions, whether or not otherwise subject to the jurisdiction of the Commission. 95/ Section 311 of the FPA further provides that the Commission shall secure and keep current information regarding the cost of generation of electric energy. 96/

Thus, the Commission has ample authority to collect system lambda data, since these data reflect the incremental cost of energy, and the Commission has explicit (sections 304 and 311) and implied (section 309) authority to collect information regarding the cost of generating electric energy.

Finally, one commenter requests that: (1) hourly system lambda data start at 1 a.m. (instead of 12 midnight) on January 1, consistent with current industry practices for collecting hourly demand data, and (2) "N.A." be entered for hours when the dispatch computer is not operating. 97/ The final rule adopts both suggestions.

3. Planning Area Hourly Demand Data

The Commission is replacing the current reporting of demand data (i.e., Schedule X -- Planning Area Monthly Net Energy for Load, Schedule XI -- Planning Area Summer and Winter Actual and Forecast Peak Demand and Annual Net Energy for Load, and Schedule XII -- Planning Area Hourly Demand Data By Specified Week) with a requirement that Respondents report in electronic form: (1) the

95/ 16 U.S.C. 825j.

96/ 16 U.S.C. 825j.

97/ See LG&E Energy Comments at 2.

historical hourly demands for planning areas for the reporting year, and (2) the forecast summer and winter peak demands and net energy for load for each of the next ten years.

Most commenters support this change. 98/ However, a few commenters state that the submission of hourly and seasonal demand and hourly load data does not achieve the purpose of the rulemaking: that is, it does not enable potential transmission customers to assess available transmission capacity. 99/ The Commission is proposing to collect hourly system load data as part of Form 714, not as part of Form 715. As noted above, the regulatory purpose for collecting Form 714 data (e.g., bulk power transfer and interconnected operations analyses) is not changed. Furthermore, if the Commission performs a production simulation study involving the analysis of actual hourly data, the change in reporting requirements eliminates the need to impute a relationship between the summary statistics previously reported and actual hourly data. Also, by requiring hourly data, the Commission can more easily and accurately aggregate respondents' load information.

The final rule also requires Respondents to authorize their regional organization to make hourly demand and forecast demand information available in an easily accessible format.

98/ See, e.g., EEI Comments at 27; Western Entities Considering Formation of Regional Transmission Group(s) Comments at 7-8; Allegheny Power Service Comments at 6; Atlantic Electric Comments at 7; Duquesne Light Comments at 7.

99/ See, e g., Oglethorpe Power Corporation Comments at 11; Southern Company Services Comments at 20-21.

Consistent with this requirement, commenters indicate that NERC already collects and maintains an hourly load data system for most utilities in the country in EEI format. 100/ In addition, consistent with the change in reporting for hourly system lambda data, the Commission is modifying Part III, Schedule 2 of Form 714 to require reporting of hourly demand data beginning at 1 a.m. on January 1.

D. Market Power

The Commission stated in the NOPR that the availability of transmission information should help mitigate a potential source of a transmitting utility's market power. 101/ Some commenters support the statement; 102/ others disagree. 103/ For example, one commenter states that Congress did not enact § 213(b) because it was concerned about market power. 104/

The Commission disagrees. Section 213(b) requires the Commission to collect information regarding available transmission capacity and known constraints. It is important to

100/ See, e.g., EEI Comments at 27-28; Electric Reliability Council of Texas (ERCOT) Comments at 2.

101/ 58 FR 17548; IV FERC Stats. & Regs. ¶ 32,493 at 32,693.

102/ See, e.g., APPA Comments at 2; Duquesne Light Comments at 1-2; American Iron and Steel Institute, et al. Comments at 3-4; DOE Comments at 2; Transmission Access Policy Study Group Comments at 6.

103/ See, e.g., Central Louisiana Electric Comments at 4; EEI Comments at 6-7; Allegheny Power Service Comments at 2.

104/ See Duke Power Comments at 21.

view the § 213(b) information requirements in their appropriate context. Congress added § 213 to the FPA to support the concurrent changes that it made to §§ 211 and 212, which give the Commission additional authority to order transmission service. The Members of the House Committee on Energy and Commerce note in their comments that:

> Congress' objective of increasing the efficiency of the electricity markets through a more open transmission system can only be achieved if basic information about the system is publicly available. [105/]

Eliminating the ability to withhold basic transmission information reduces the potential for abuse of market power and will increase efficiency in the wholesale electric market.

Another commenter claims that the Energy Policy Act removes its market power in transmission. 106/ We do not agree. The Commission's new authority to order transmission service under § 211 does not by itself eliminate market power in transmission. Market power may lie in the ability to delay or to undermine the process of requesting service. While the Commission addressed the formal process of service requests in its recent policy statement on good faith requests for transmission services and

105/ Members of the House Committee on Energy and Commerce Comments at 1. Cf. H.R. Rep. No. 102-474, 102nd Cong. 2nd Sess. pt 1 at 132-138 (1992).

106/ See, Allegheny Power Service Comments at 2.

responses, 107/ there still remains a basic information asymmetry that impedes efficient resource choices and market results. Superior knowledge of and access to technical information on transmission system availability may result in competitive advantages. Consequently, the availability of information regarding transmission capacity and known constraints helps to mitigate a potential source of market power and promotes a "more level playing field" for buyers and sellers.

E. General Filing Requirements

1. Form 715 Respondents

A number of commenters, many representing small systems, raise concerns regarding exemptions from or waivers of Form 715. In the NOPR, the Commission proposed that the reporting requirements apply to transmitting utilities that own or operate transmission facilities at or above 100 kilovolts (kV). 108/ Commenters state that many entities that technically may be transmitting utilities do not engage in transmission planning because they: (1) do not operate the transmission line (because they lease or are a joint owner of transmission facilities); or

107/ Policy Statement Regarding Good Faith Requests for Transmission Services and Responses by Transmitting Utilities Under Sections 211(a) and 213(a) of the Federal Power Act, as Amended and Added by the Energy Policy Act of 1992, 58 FR 38964 (July 21, 1993), III FERC Stats. and Regs. ¶ 30,975.

108/ 58 FR 17544, 17550; IV FERC Stats. & Regs. ¶ 32,493 at 32,686, 32,695.

(2) operate only radial lines. 109/ Some commenters also note that operators of these facilities may be "small-business concerns" as defined in § 3 of the Small Business Act, (15 U.S.C. § 632) and thus require special consideration. 110/

Upon further consideration, we will require only transmitting utilities operating integrated transmission system (i.e., non-radial) facilities that are rated at or above 100 kV to report Form 715. In cases of joint ownership of a facility, only the operator of the facility must report. This change avoids duplication of reported information. Similarly, we will not require operators of only radial transmission lines to file Form 715 data; we expect few requests for transmission service that would use such facilities exclusively.

We will retain the 100 kV threshold for transmission facilities. Because the capacity of lines below 100 kV is relatively small, those lines do not provide significant amounts of transmission service. This threshold also eliminates the reporting requirement for most small business entities.

Some commenters indicate that if an entity other than the

109/ See, e.g., Oregon Trail Consumers Cooperative Comments at 2-5; PSI Energy Comments at 3-4; North Texas Electric Cooperative Comments at 2-5; Old Dominion Electric Cooperative Comments at 11; Northwest Cogeneration and Industrial Power Comments at 1-2; Southwest Regional Transmission Association Comments at 12; Texas-New Mexico Power Comments at 10-11; City of Vernon Comments at 5-6; National Independent Energy Producers Comments at 4; Utah Associated Municipal Power Systems Comments at 14.

110/ See, e.g., American Forest & Paper Association Comments at 2; Oxbow Geothermal Corporation Comments at 3-4; Allegheny Electric Cooperative Comments at 13.

party requesting waiver of Form 715 performs transmission planning for that party: (1) the waiver requirements generate confusion regarding the party responsible for reporting information, and (2) obtaining the planning information required by the rule from the other party is sometimes difficult. 111/ The final rule requires that an entity requesting waiver must either: (1) indicate the entity that performs transmission planning for it, or (2) state that it does not use power flow analyses in performing transmission planning.

Once granted, a waiver request in subsequent years is unnecessary, provided the party's status does not change; that is, as long as the party does not begin to perform transmission planning or to use power flow analyses in its planning. Exemption or granting of waiver from Form 715 reporting requirements does not affect an entity's status as a transmitting utility for other purposes under the FPA, such as the applicability of §§ 211 and 213(a).

One commenter requests an exemption from Form 715 requirements for facilities used primarily to deliver energy to affiliates for use in manufacturing. 112/ We will not grant this proposed exemption because an affiliate could operate facilities that are a part of the integrated transmission system.

111/ See, e.g., Oxbow Geothermal Corporation Comments at 3; Transmission Agency of Northern California Comments at 2; Southwestern Public Service Comments at 2-3; New England Electric Service Comments at 6-7; Allegheny Power Service Comments at 3.

112/ Alcoa Companies Comments at 1-12.

for which Form 715 reporting is appropriate. The radial line exemption and 100 kV threshold provide sufficient protection for small entities, including many manufacturing affiliates of transmitting utilities.

2. Filing Date

a. Form 715

The NOPR established a January 1 filing date for Form 715. Several commenters request that the filing date be moved to later in the year. 113/ Many commenters also suggest that the filing date coincide with either that for the DOE OE-411 report, which is a voluntary filing by regional reliability councils (April 1), FERC Form No. 1 (April 30), or Form 714 (currently May 1). 114/ Commenters state that filing several forms at the same time promotes administrative efficiency and data consistency. 115/ The Commission's experience, however, is that a significant number of Respondents, especially those required to file Form 714, request extensions of time to file because of the difficulty in completing all the reporting forms at the same time.

Some commenters state that they cannot supply historical

113/ See, e.g., ERCOT Comments at 2; Colorado Association of Municipal Utilities Comments at 1.

114/ See, e.g., Atlantic City Electric Comments at 3; Commonwealth Edison, et al. Comments at 3; Western Group Considering Formation of RTG(s) Comments at 9-10.

115/ See, e.g., Atlantic City Electric Comments at 8; Western Systems Coordinating Council Comments at 4; Northeast Utilities Comments at 4.

data immediately after the end of the year. 116/ These commenters apparently confuse Form 715 with Form 714. Form 715 does not require historical information. The filing date for Form 714, which requires the reporting of some historical data, has been May 1.

Upon consideration of the comments and to provide for a reporting consistent with utility and regional planning schedules, we will change the filing date for Form 715 to April 1.

Finally, several commenters request that the Commission delay the collection of information until 1995. 117/ Given the deadline imposed by Congress for Commission regulations implementing data collection (October 24, 1993), we will adopt a filing date of April 1, 1994. This is sufficient time for Respondents to develop and provide the information, especially because most of the requested information is produced in the normal course of business.

b. Form 714

Respondents currently file Form 714 no later than May 1 of the year following the calendar reporting year. One commenter requests a delay in the Form 714 filing date until June 1, the

116/ See, e.g., Large Public Power Council Comments at 21; Southwest Regional Transmission Association Comments at 8.

117/ See, e.g., Western Systems Coordinating Council Comments at 4; Large Public Power Council Comments at 21; Southwest Regional Transmission Association Comments at 8

date on which it submits hourly demand information to NERC. 118/ The final rule adopts the suggestion.

Two commenters request that the Commission delay the collection of hourly system lambda until 1995 because some systems do not collect such data. 119/ The Commission will deny this request. Entities have reported system lambda information since 1990. Respondents have had ample time to add necessary software or to adjust computer systems in order to record system lambda data. In addition, calculation of the previously required monthly system lambda statistics requires averaging of hourly data, which Respondents must now report. Therefore, entities which must file a Form 714 should be able to satisfy the modified reporting requirement without significant additional investment. Respondents must file hourly system lambda data by the June 1, 1994 filing date of the next Form 714 report.

F. Section-by-Section Analysis of Form 715

1. Part 1 - Identification and Certification

Part 1 requires that Respondents file the following identifying information:

(1) the name and business address of the transmitting utility;

118/ See ECAR Comments at 4.

119/ See City of Colorado Springs Comments at 7; and Western Group Considering Formation of RTO(s) Comments at 9-10.

(2) the name, title, telephone number, and facsimile number of a person to contact regarding Form 715 data;

(3) a certification by an authorized official of the transmitting utility regarding the accuracy of the data submitted; and

(4) the name and title of the certifying official.

One commenter requests that Part 1 data also include information identifying the individuals in charge of transmission system planning, transmission system operations, and transmission service contracting. 120/ Such information would inform interested parties of whom to contact regarding technical and contracting information. Another commenter requests that Form 715 include a section identifying a contact person for § 213(a) transmission service requests. 121/

The Commission rejects these proposed additions. Part 1 is intended to gather only information necessary to implement the requirements of § 213(b). Information regarding specific transmission service requests, including requests under § 213(a), is not within the scope of Form 715. The purpose of the contact person requirement is to identify a point of contact at the transmitting utility for inquiries regarding Form 715 data. However, a transmitting utility may, at its option, include in its Part 1 response the person to contact regarding specific

120/ See APPA Comments at 9.

121/ See EEI Comments at 18.

transmission service requests. 122/

2. Part 2 - Regional or Subregional Power Flow Base Cases

There is nearly universal agreement that the ability to simulate power flows on a transmission grid is a necessary first step in determining available transmission capacity and constraints on that grid. To give potential transmission customers and the public this ability, the NOPR proposed that transmitting utilities authorize their regional or subregional organizations to make available base case power flow data.

Generally, the regional organizations support this proposal. 123/ It is these organizations that develop base case power flows for their members' use and, under Part 2, that will make them available to potential transmission customers and the public. Most individual transmitting utilities also support the intent of Part 2. 124/

In the NOPR, the Commission requested comments on ways in which transmitting utilities or regional or subregional entities could best make the electronic data available to the public. Comments from regional entities support making the data available

122/ One of the goals of making Form 715 data available is to foster successful negotiations that culminate in voluntary transmission agreements. Identifying individuals that will respond to specific requests would simplify the initiation of this process.

123/ See, e.g., NERC Comments at 2; ERCOT Comments at 1; Mid-America Interconnected Network Comments at 2; Mid-Continent Area Power Pool Comments at 6.

124/ See, e.g., EEI Comments at 9; APPA Comments at 6; Allegheny Power Service Comments at 3; Atlantic Electric Comments at 4-5; Idaho Power Comments at 1; Duke Power Comments at 23.

on diskette 125/ in a format similar to those suggested in the NOPR. 126/ The Commission is modifying the instructions for Part 2 to make clear that the Commission is not recommending any particular format. However, to ensure that information is reported on a consistent and useful basis for a region, the format used must be associated with the power flow program used by that region.

One commenter claims that the IEEE Common Format is obsolete and that the Electric Power Consultants' (EPC) format contains a more meaningful set of input data. 127/ Another commenter supports the use of the IEEE Common Format. 128/ The Commission is adding EPC raw data file format to the list of commonly used formats for reporting power flow data in Part 2. Although the IEEE Common Format will be retained, it does not appear that it is currently being used to develop input data for the commonly used power flow programs. The Commission does not encourage translation of data into input formats other than those

125/ Reaction to the use of Electronic Bulletin Boards is mixed. The Southwest Power Pool members now have access to power flow models through dial-up capability. See Southwest Power Pool Comments at 4. ECAR, however, contends that it is impractical. See ECAR Comments at 4. The Commission will not require Electronic Bulletin Board access at this time, but encourages its use when practical.

126/ See, e.g., ECAR Comments at 3; Mid-Continent Area Power Pool Comments at 5; Southwest Regional Transmission Association Comments at 8; Group of Western Entities Considering Formation of RTG(s) Comments at Appendix.

127/ APPA Comments at 10.

128/ Pennsylvania-New Jersey-Maryland Interconnection Comments at 5.

used in the region due to the risk that vital information necessary to solve the power flows will be lost.

Two commenters express concern that power flow software documentation (with the exception of the IEEE common format) may be copyrighted and proprietary and therefore not be readily available. 129/ They note that users need software manuals and papers to interpret the power flow cases. According to these commenters, if the Commission or others publish this information, they risk violating such copyrights. The concerns of these commenters are unfounded. The Commission is not recommending the unauthorized distribution, nor will it provide, licensed software to the public. To use the information in Part 2, a potential transmission customer or member of the public must have software compatible with that used in the region. No other commenters have suggested that the power flow data required under this rule are proprietary because of vendor license conditions.

Several commenters within Texas are concerned that regional power flow data will reveal industrial load levels that industrial customers consider proprietary and confidential. 130/ ERCOT now requires users of power flow data to specify what they will do with it and to agree not to provide it to a third party. The Commission will not allow restrictions on the

129/ Electrocon International Comments at 1; New England Electric System Comments at 6.

130/ See, e.g., ERCOT Comments at 2; Houston Lighting and Power Comments at 4; Texas Utilities Comments at 4; Central & Southwest Comments at 8-9; Texas-New Mexico Comments at 10.

use of these data. If the information is shared by all within ERCOT for purposes of transmission planning, then it must be available to potential transmission customers and the public. Conditioning the use of these data would be inconsistent with the public availability requirement of § 213(b).

Regional groups and others suggest that the Commission should allow them to charge the administrative costs of providing this information to the public. 131/ The Commission finds that recovering the cost to copy materials is reasonable. However, transmitting utilities may not assess copying charges to those entities (such as the Commission and other regulatory, planning and siting agencies) which have statutory authority to require the filing of the information with such entity. If Respondents desire to impose copying charges, Form 715 requires Respondents to include the fee schedule for making the information available to the public. Transmitting utilities must also provide for on-site inspection of data.

Some commenters suggest that transmitting utilities should update the data in Form 715 during the year when there are significant changes. 132/ Because § 213(b) requires an annual submission, the Commission will not require the filing of

131/ See, e.g., ECAR Comments at 4; ERCOT Comments at 2; Mid-America Interconnected Network Comments at 3; Southwest Regional Transmission Association Comments at 7; Group of Western Entities Considering Formation of RTO(s) Comments at 9.

132/ See, e.g., APPA Comments at 4; American Iron and Steel Institute, et al. Comments at 5; LG&E Energy Comments at 4.

updated information between reporting dates. However, we agree with those commenters who say that transmitting utilities should have the opportunity to update criteria and practices (and presumably power flow data) as needed to help avoid misunderstandings. 133/ Consequently, we would expect regional entities, upon request, to supply the most current criteria, practices and power flow data available, beyond those in the Form 715 on file with us. Transmitting utilities need not file this up-dated information and data with us until the next Form 715 submission.

Several commenters suggest that the 100 kV threshold should not apply to power flow data bases made available under Part 2. 134/ This is not the Commission's intent. The 100 kV threshold determines only who must file Form 715. The base case power flow data made available by a regional entity should include all voltage levels used in developing the regional base cases.

Some commenters suggest that Part 2 should cover additional information beyond that proposed. One commenter provides a list of generating unit information that some power flow programs can

133/ See, e.g., EEI Comments at 12; LG&E Energy Comments at 3-4; PSI Energy Comments at 4-5.

134/ See, e.g., APPA Comments at 5-6; Transmission Access Policy Study Group Comments at 15; National Rural Electric Cooperative Association, et al. Comments at 4-5; Municipal Energy Agency of Nebraska Comments at 2-3; American Iron and Steel Institute, et al. Comments at 6.

use to dispatch generation on an economic basis. 135/

Some redispatch of the generation output in a power flow program is generally necessary to simulate a proposed power transfer on the transmission system. However, for purposes of preliminary studies, transmitting utilities can dispatch generation in various ways other than through the use of an economic dispatch algorithm; that is, without the need for detailed, unit-specific data. Therefore, the Commission does not find that this information is necessary to perform preliminary studies based on the power flow input data that transmitting utilities will make available under Part 2. However, if the regional power flow data base cases provided to members already contain economic dispatch data, then transmitting utilities must release that data to the public.

Other commenters suggest that system stability may limit transmission availability in certain regions and that, therefore, these regions should provide stability studies, 136/ or the data needed to perform stability studies, to a requester. 137/ Also, a number of electric utilities state that the power flow data without stability data will not be sufficient to

135/ APPA Comments at Attachment C.

136/ Stability studies are studies of the measures that transmitting utilities must take to maintain the synchronization of their generating units after a disturbance.

137/ See, e.g., APPA Comments at 15; DOE Comments at 9, Electric Power Consultants Comments at 1; Professor Choudhry of West Virginia University Comments at 1.

conduct useful preliminary studies. 138/

While a more detailed and comprehensive analysis of a proposed use of the transmission system in certain regions may require a stability study, the Commission does not find it necessary to require the regional entities to provide the more voluminous input data necessary to perform stability studies, if stability is not identified as a limiting factor in their regional power flow analyses. The Commission notes that a number of other studies, such as voltage stability and other specialized analyses of suspected system dynamic problems, may also affect the outcome of power flow analyses. In light of the fact that Form 715 data will generally be used for preliminary analyses, the Commission is not requiring transmitting utilities to provide the data for such studies. However, the instructions in Part 6 of Form 715 provide that, if stability is identified in studies as a regional transmission limiting factor, transmitting utilities must, on request, provide a requester with the results of existing regional stability studies.

Two state commissions express concern whether planning data reflected in the power flow base cases will also reflect planning done under state authority. 139/ The Commission

138/ See, e.g., San Diego Gas & Electric Comments at 2-3; Minnesota Power & Light Comments at 3; Otter Tail Power Comments at 3; Public Generating Pool Comments at 3; Montana-Dakota Utilities Comments at 2; Large Public Power Council Comments at 5.

139/ See Public Service Commission of Wisconsin Comments at 2-3; Massachusetts Department of Public Utilities Comments at 4-5.

expects that utilities will provide information consistent with that provided to their state commissions.

3. Part 3 - Transmitting Utility Maps and Diagrams

Part 3 requires transmitting utilities to file two copies of their general transmission maps and single-line schematic diagrams of their transmission systems. Specific guidelines indicate the type of information (such as geographic location of generating plants, switching stations, substations, service areas, and interconnections with other utilities) and the level of detail (for example, nominal operating and design voltages of transmission lines) that transmitting utilities must include in the maps and diagrams. The Commission is not requiring Respondents to create new maps and diagrams for purposes of this reporting requirement Transmitting utilities must file only those maps and diagrams prepared in the normal course of business.

Some commenters contend that the Part 3 requirement is more involved than the current Form 714 requirement. 140/ They suggest relaxing the requirement to no more than the level of detail included in regional maps submitted as part of DOE OE-411 reports.

The data that transmitting utilities must file under this part are no different from those required in Part II, Schedule XV of the current Form 714. The detail required by Part 3 has not

140/ See, e g., American Electric Power Comments at 5-6; Pennsylvania-New Jersey-Maryland Interconnection Comments at 8-9; New England Power Pool Comments at 1.

changed from existing requirements that have been effective for many years. The current Form 714 and its predecessor forms (EIA Form 714 and Federal Power Commission Form 12) require Respondents to submit maps with the same level of detail as that required by Part 3. Although the applicability of the requirement to file maps and diagrams is slightly different under Form 715 than Form 714, 141/ most transmitting utilities currently file Form 714. Consequently, there is no change in the filing requirement for these entities. Furthermore, the Commission is not requiring entities that do not currently produce maps and diagrams to create such documents solely for the purpose of Part 3 reporting.

Additionally, a Respondent that has not produced more recent maps and diagrams than those currently on file at the Commission need not re-submit the same maps and diagrams each year. In such a case, a Respondent will file a statement indicating that a more recent set of maps and diagrams is not available.

Because of the expected interest in Form 715 information, the Commission will require transmitting utilities to file two copies of maps and diagrams. This requirement will enable the Commission to keep a copy available in the Commission's public reference room and to use the other copy. If a Respondent has up-to-date maps and diagrams on file, it need only file one

141/ Form 714 requires electric utilities with an annual peak demand greater than 200 megawatts to file maps and diagrams. Form 715 filing requirements are applicable to transmitting utilities.

additional copy of its maps and diagrams with its Form 715 report.

4. Part 4 - Transmission Planning Reliability Criteria

In the NOPR, the Commission requested comments on the proposed requirement that Respondents submit transmission planning reliability criteria that the transmitting utility uses to assess the limits of its transmission system to meet its load responsibility as well as to move bulk power among other electric systems. The Commission also proposed guidelines to indicate the type of information that Respondents might provide to satisfy this requirement. The guidelines included documents that contain transmission reliability criteria of NERC, regional reliability councils, or DOE OE-411 reports. In addition to these documents, the rule would have required the Respondent to submit all criteria that are enforced on its system. The criteria could be imposed by the Respondent itself or pursuant to interconnection or pooling agreements with others. In the proposed rule, the test for adequacy of submitted information was that, using the same reliability criteria, others should be able to "reasonably replicate" studies done by the Respondent.

Many commenters support allowing individual Respondents to reference appropriate NERC publications and DOE OE-411 reports in order to satisfy Part 4 requirements. They state that these criteria may be sufficient for transmission service requesters who require information on established regional transmission

planning reliability criteria. 142/ A few commenters, however, state that existing DOE OE-411 report criteria, alone, are sufficient to satisfy the requirements of Part 4. 143/ A number of regional and pool commenters support submittal of transmission reliability criteria, but state that individual utilities would have to supply criteria specific to their systems. 144/ Some commenters interpret the proposed rule as permitting utilities to submit additional system-specific planning criteria 145/, or allowing submittal upon request. 146/ For example, Duke Power Company indicates that it has internal criteria that are not in written form, and it would be extremely burdensome to reduce these criteria to written form, because the criteria involve the application of subjective engineering judgments. 147/ Two transmission-owning commenters support the requirement for submittal of specific criteria, with one commenter recommending that the Commission require individual utilities to document and explain the

142/ See, e.g., EEI Comments at 11; Boston Edison Comments at 2; Union Electric Comments at 6-7; Oglethorpe Power Corporation Comments at 6.

143/ See, e.g., Dayton Power and Light Comments at 3; Northern States Power Comments at 9.

144/ See, e.g , New England Power Pool Comments at 2; Northeast Power Coordinating Council Comments at 2; Pennsylvania-New Jersey-Maryland Interconnection Comments at 9-10.

145/ See EEI Comments at 11; Allegheny Power System Comments at 3-4; Union Electric Comments at 7.

146/ See Boston Edison Comments at 2.

147/ See Duke Power Comments at 25.

engineering basis for the reliability criteria. 148/

In addition to their regional criteria, Respondents must submit system-specific planning criteria. Unless Respondents make such criteria publicly available, a potential user of the system will have little idea of system specific criteria that might limit transmission availability. As stated above, the Commission's intention is that transmitting utilities file the substantive criteria and planning procedures that they follow in the normal course of business.

We have removed the terms "in totality" and "reasonably replicate" from the instructions to Form 715 and have revised the Part 4 instructions to make clear that the transmission planning criteria must be in sufficient detail to allow others to perform similar planning or screening studies, and to better understand the process of determining available transmission capacity.

Two commenters are concerned that once Respondents supply their reliability criteria, they will be unable to modify them as needed. 149/ The Commission will not require Respondents to update their submittals immediately upon a change in reliability criteria. However, Respondents must reflect revised criteria in their next Form 715 filing. In addition, in their next Form 715 filing, Respondents will also be required to identify any changes from their prior year's report.

148/ See Public Service Electric and Gas Comments at 3, Duquesne Light Comments at 5.

149/ See EEI Comments at 12; Florida Power & Light Comments at 5-6.

One commenter recommends that the Commission require each transmitting utility to file a description of its transmission planning process and list specific items that transmitting utilities should provide to potential transmission users. 150/ Another commenter suggests that the Commission provide guidance on the format and level of detail to be used by Respondents that do not document individual system reliability criteria. 151/ A commenter requests that reliability criteria rules also specify the relationship between planning criteria and actual system operation, and define reliability policies. 152/ Another commenter recommends that the Commission require transmitting utilities to document the method used to assess the effect of a wheeling transaction on the transmitting utility's system. 153/

Because only existing reliability criteria are to be reported, the Commission is not establishing standards or requiring a particular format. We, therefore, will not adopt these suggestions.

5. Part 5 - Transmission Planning Assessment Practices

In the NOPR, the Commission requested comments on the proposal to require submittal of transmission planning assessment practices that the transmitting utility uses to apply its

150/ APPA Comments at 12-13 and 31-32.

151/ Oglethorpe Power Comments at 7.

152/ National Independent Energy Producers Comments at 3-4.

153/ Electric Power Consultants Comments at 2.

particular reliability criteria. The Commission also provided guidelines on what might constitute transmission planning assessment practices. Included in the guidelines was a proposal to require the transmitting utility to submit a list of critical facilities that are generally used in performing its contingency studies. As in Part 4, the Commission proposed that the information provided in Part 5 should be in sufficient detail to allow others to reasonably replicate planning studies done by the Respondent.

We have removed the term "critical facilities" from the instructions. 154/ We have also re-written the second paragraph of the Part 5 instructions to make clear that a transmitting utility need only submit a list of contingencies that are generally considered as part of its assessment of system performance. 155/

Some commenters agree that transmission planning assessment practices are important in determining transmission capacity and constraints, but state that utilities cannot describe, in sufficient detail for all possible cases, certain assessment practices which have been developed through experience, study and

154/ See NERC Comments at 6.

155/ For example, before testing for the limits of transmission capability that could be used for firm power transfers on its system, a transmitting utility will assume, based on experience or realistic expectation, that certain facilities will be unavailable for certain periods.

an interactive review process. 156/

Northern States Power states that requiring Respondents to file transmission planning practices is duplicative because transmitting utilities already include this information in DOE OE-411 reports. 157/ Otter Tail Power is concerned that a listing of "proposed" system additions could create a financial liability for the Respondent. 158/ Pacific Gas & Electric states that it has no comprehensive document describing transmission planning and assessment practices, but is prepared to submit any existing documents that relate to the requested information. 159/ Large Public Power Council states that the data gathered would not be sufficient to perform screening studies. 160/ However, DOE states that submission of transmission planning assessment practices, together with the other information provided, will enable potential transmission users to do their own first-cut analysis of transmission availability. 161/ Florida Power & Light Company cautions that the reporting requirements must not constrain the utility's

156/ See, e.g., New England Power Pool Comments at 2; Pennsylvania-New Jersey-Maryland Interconnection Comments at 10-11; EEI Comments at 13-14; Boston Edison Comments at 3; Central Maine Power Comments at 2; Florida Power and Light Comments at 5-6; Northeast Utilities Comments at 3.

157/ Northern States Power Comments at 9.

158/ Otter Tail Power Comments at 5.

159/ Pacific Gas & Electric Comments at 9.

160/ Large Public Power Council Comments at 7-8.

161/ DOE Comments at 3-4.

ability to modify its transmission planning assessment practices. 162/

As in Part 4, the Commission's objective is to require submittal of the substantive planning assessment practices that a Respondent follows in the normal course of business. The information filed should help requesters to perform screening analyses and to better understand the process of determining available transmission capacity and known constraints. As in the case of Part 4 material, the Commission will require transmitting utilities to file changes in their transmission planning assessment practices on an annual basis, as part of Form 715.

Oglethorpe Power Corporation states that Form 715 information should specifically address any economic and financial factors governing system planning decisions, including state or Federal regulatory constraints (such as siting and licensing approval requirements, or the ability to recover incremental facility expansion costs). 163/ The Commission will not adopt these suggestions because they are overly broad and have nothing to do with the reporting of planning assessment practices necessary in the context of § 213(b).

6. Part 6 - Evaluation of Transmission System Performance

In the NOPR, the Commission requested comments on the proposed requirement that Respondents submit evaluations of their transmission system performance for future time periods based on

162/ Florida Power & Light Comments at 5-6.

163/ Oglethorpe Power Corporation Comments at 8-9.

the application of their reliability criteria. As proposed, the evaluation would provide potential transmission customers and regulators with a clear understanding of existing and, where known, likely future transmission constraints, the location of such constraints, and how they were identified, as well as a description of any plans to mitigate the constraints. The Commission also proposed that transmitting utilities submit the results of any dynamic stability studies that set transmission limits. The proposed rule characterized the evaluation as being separate from traditional utility studies that are not usually undertaken unless there is a specific need.

Some commenters claim that Part 6 requirements would cause a significant burden, if the filing of existing planning studies is considered insufficient. 164/ Many transmitting utilities state that, if they are to develop and file Form 715 within the projected 100 hours timeframe for completing the form, only a narrative description for Part 6 should be required, and new evaluations should not be required where none currently exist. 165/ As discussed above, the Part 6 instructions require only a narrative description.

164/ See, e.g., New England Power Pool Comments at 2; Northeast Power Coordinating Council Comments at 2; Southwest Regional Transmission Association Comments at 12-13; Allegheny Power Comments at 4; TVA Comments at 2.

165/ See, e.g., Pennsylvania-New Jersey-Maryland Interconnection Comments at 13; EEI Comments at 16; Allegheny Power Comments at 4; American Electric Power Comments at 7-8; Northeast Utilities Comments at 4; PSI Energy Comments at 6; Southwestern Public Service Comments at 6-7.

A few commenters state that the Commission should limit the Part 6 portion of the filing to information that a utility prepares in the normal course of planning and operating its transmission system, and should not impose a requirement for additional studies. 166/ Florida Power and Light Company states that transmitting utilities cannot fulfill the proposed requirement that owners of transmission facilities provide detailed descriptions of all expected constraints and mitigation plans unless they have a specific list of expected uses for their transmission system. 167/

Northern States Power is concerned that the rule provides no clear time frame for assessment. It states that, if the analyses are for a short term, they will not provide any useful information on long-term transmission capacity availability; and if they are for a long term, they must by their very nature include assumptions regarding the future that may not turn out to be true. 168/ Midwest Power Systems Incorporated asks the Commission to clarify the definition of "transmission constraint" and to include in the definition thresholds for factors such as costs, overloads, and low voltage. 169/ Texas-New Mexico Power Company proposes that the Commission address the issue of

166/ See, e.g., Duke Power Comments at 32-33; Union Electric Comments at 9-10.

167/ Florida Power and Light Comments at 5.

168/ Northern States Power Comments at 10.

169/ Midwest Power Systems Comments at 3-4

the maximum amount of capacity a utility may set aside in a given corridor for uses such as load growth, load swings and inadvertent flows. 170/

The Commission anticipates that for the most part only existing information will need to be filed to comply with Part 6 requirements. However, evaluation of the transmitting utility's system to take into account potential transactions beyond those already planned for is necessary in order to satisfy the statutory objective of identifying available transmission capacity and known constraints. To minimize the Respondent's burden, the Commission will accept narrative descriptions of existing and future transmission system performance that identify known and future constraints and proposed mitigating actions. The Commission recognizes that transmitting utilities cannot be held strictly accountable if their predictions turn out to be inaccurate; that is, when they do not correctly anticipate the results of a particular proposed transaction. The Commission has revised the language of the rule to reflect this discussion.

Some commenters point out that it may take a long time to perform system evaluations and that it would be very burdensome to require a transmitting utility to provide evaluations using power flow base cases submitted in Part 2 for the current year. 171/ The Commission recognizes that requiring use of power

170/ Texas-New Mexico Power Comments at 15.

171/ See, e.g., Pennsylvania-New Jersey-Maryland Interconnection Comments at 13; EEI Comments at 15.

flows submitted in Part 2 would be impractical due to the time constraints and has rewritten Part 6 accordingly.

A few commenters state that it is important to submit stability studies as part of the evaluation. 172/ The Commission finds that stability studies will be useful in screening studies to assess transmission availability only when stability is the constraining factor in transmission. The instructions have been modified to require that transmitting utilities make available the results of stability studies when stability is a limiting factor in the existing or planned transmission system.

A number of commenters state that a transmitting utility should provide only existing transmission capability studies performed as part of DOE OE-411 reports (for 230 kV and above) or as part of pool or regional reliability council requirements. 173/ While the Commission will accept transmission capability studies as part of the transmission system evaluation narrative, they alone may not be adequate to meet future assessments of the transmission system.

A number of commenters propose that Respondents provide certain specific information so that others can evaluate

172/ See, e.g., Utah Associated Municipal Power Systems Comments at 13; American Iron and Steel Institute, et al. Comments at 10-11.

173/ See, e.g., Atlantic Electric Comments at 6, Boston Edison Comments at 4; Central & Southwest Comments at 10-13, 16-17.

transmission availability and identify the constraints. 174/ The Commission will not adopt these suggestions. The ability to be more specific at this stage may well impose a burden beyond that required to meet our responsibilities.

A number of commenters suggest that any operating guides or criteria that transmitting utilities may implement must be available or described in detail, to help transmission dependent entities understand the permissible uses of the network and its capabilities, and because a utility's transmission system operating criteria may vary from the planning criteria submitted. 175/ Respondents may draw upon operating studies to establish transmission transfer limits, but the explicit reporting of operating criteria is not necessary to meet our responsibilities.

IV. INFORMATION COLLECTION STATEMENT

The Office of Management and Budget's (OMB) regulations 176/ require that OMB approve certain information and record-keeping requirements imposed by an agency. The information requirements contained in this proposed rule are contained in FERC-715 "Annual Transmission Planning and Evaluation Report" (1902-0167) and FERC-714 (1902-0140). The Commission uses the

174/ See, e.g., Duquesne Light Comments at 6-7; National Power PLC Comments at 4-5; ERCOT Comments at 3.

175/ See, e.g., APPA Comments at 14-15; American Iron and Steel Institute, et al. Comments at 10; Oglethorpe Power Comments at 8.

176/ 5 CFR 1320.12.

data collected in these information requirements to carry out its regulatory responsibilities under the FPA, PURPA and the Energy Policy Act. Moreover, the collection of Form 715 data is mandated by the Energy Policy Act. The Commission's Office of Electric Power Regulation uses the Form 714 data to obtain a better overall picture of annual power generation and transmission and to ensure consistency in the reporting of operational data by the electric utility industry. In particular, the data collected provides greater comprehension of interconnected control area operations. The Commission also has deleted certain reporting requirements from the Form 714 because the Commission can obtain the data from Form 715.

The Commission is notifying the Office of Management and Budget that it is modifying its proposed information requirements. Interested persons may obtain information on these reporting requirements by contacting the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, DC 20426 [Attention: Michael Miller, Information Services Division (202) 208-1415]. Comments on the requirements of the final rule can be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission].

V. REGULATORY FLEXIBILITY ACT CERTIFICATION

The Regulatory Flexibility Act requires rulemakings either to contain a description and analysis of the effect that a rule

will have on small entities or to certify that the rule will not have a significant economic effect on a substantial number of small entities. 177/ Allegheny Electric Cooperative, Inc. (Allegheny) and several other electrical cooperatives (Allegheny, et al.) 178/ challenge the Commission's certification that the proposed rule would not have a significant economic impact on a substantial number of small entities. 179/ Allegheny, et al. maintain that the proposed rule will impose new data collection and maintenance requirements on rural electrical cooperatives and small generation and transmission cooperatives that operate radial, rather than network transmission facilities.

These commenters state that electric cooperatives do not generally conduct load flow simulations or develop the type of reliability, assessment, or evaluation information that the rule would require. According to Allegheny, et al., electric cooperatives are generally not full members of NERC regional councils or sub-regional groups, and their facilities are not typically included in those groups' load flow simulations.

177/ 5 U.S.C. §§ 601-612.

178/ The other electrical cooperatives are: Four County Electric Membership Cooperative, Inc., Rayburn County Electric Cooperative, Inc. (Rayburn), Saluda River Electric Cooperative, Inc. (Saluda River) and Southern Maryland Electric Cooperative, Inc.

179/ New Reporting Requirement Under the Federal Power Act and Changes to Form No. FERC-714; Proposed Rulemaking, 58 FR 17544, 17549 (April 5, 1993); IV FERC Stats. & Regs. ¶ 32,493 at 32,694-5.

Allegheny, et al. point out that many electrical cooperatives already serve municipalities or other customers at wholesale and may well become transmitting utilities, covered by the requirements of the proposed rule, as EWGs and IPPS locate within their service areas. Allegheny, et al. fear that electrical cooperatives and small power systems may have to manufacture the required data for the sole purpose of complying with the proposed rule. 180/ Allegheny, et al. request that the Commission exempt from the Form 715 reporting requirements entities that own or operate only discrete line sections or radial facilities, and that the Commission exempt small power systems from the requirement to conduct regional power flow studies or to provide equivalent power flow cases. 181/

Although we will not grant Allegheny, et al. the exemptions they seek, we have modified the proposed rule to accommodate their concerns. To ensure that the final rule will not have a significant economic impact on a substantial number of small entities, we have made the following changes from the proposed rule:

A. In the NOPR, we proposed that both owners and operators of fully integrated and radial transmission facilities must file Form 715. In the final rule, we are requiring only operators of

180/ Allegheny, et al. Comments at 22-27.

181/ Allegheny, et al. Comments at 31-36

these facilities to file Form 715. 182/

B. The proposed rule would have included entities owning and operating only radial facilities. We have restricted the filing requirements in the final rule to operators of integrated facilities. 183/

C. In the final rule, we have allowed for waiver for those entities that do not develop or use power flows in the normal course of business. 184/

We think that our changes in the final rule have responded to the needs of small entities. Most small entities will either be exempt from our final rule or will be eligible for a waiver from its requirements. The final rule only covers the operators of integrated transmission facilities of 100 kV and above. Because most transmission utilities that operate integrated transmission facilities of 100 kV and above do not fall within

182/ Because Allegheny owns but does not operate a section of 500 kV transmission line (Allegheny, et al. Comments at 15), under the final rule it will not have to file Form 715.

183/ Because Saluda River operates only radial lines (Allegheny, et al. Comments at 25), it will not have to file Form 715.

184/ Allegheny, et al. state that electrical cooperatives do not generally conduct load flow simulations. Allegheny, et al. Comments at 24. Those cooperatives would, then, be eligible for waiver from the requirement to file Form 715.

Rayburn requests a waiver from Form 715 filing requirements. Allegheny, et al. Comments at 26. We will deny this request as premature, without prejudice to Rayburn's renewing its request for waiver once the final rule becomes effective.

the definition of "small entity," 185/ and because the final rule accommodates the economic concerns of small entities, the Commission certifies that this rule will not have a significant economic impact on a substantial number of small entities.

VI. ENVIRONMENTAL STATEMENT

Commission regulations require that an environmental assessment or an environmental impact statement be prepared for any Commission action that may have a significant adverse effect on the human environment. 186/ The Commission categorically excludes certain actions from this requirement as not having a significant effect on the human environment. 187/ No environmental consideration is necessary for the promulgation of a rule that involves the gathering, analysis, and dissemination of information. 188/ Because this final rule involves only the gathering, analysis and dissemination of information, no environmental consideration is necessary.

VII. EFFECTIVE DATE

This final rule is effective [insert date 30 days after date of publication in the Federal Register]. The information

185/ 5 U.S.C. § 601(3), citing to section 3 of the Small Business Act, 15 U.S.C. § 632, which defines a "small-business concern" as a business that is independently owned and operated and that is not dominant in its field of operation.

186/ Regulations Implementing National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987); FERC Stats. and Regs., Regulations Preambles 1986-1990, ¶ 30,783 (1987).

187/ 18 CFR § 380.4.

188/ 18 CFR 380.4(a)(5).

collection provisions, however, will not become effective until approved by the Office of Management and Budget. Notice of this date will be published in the Federal Register.

List of Subjects in 18 CFR Part 141

Electric Power, Reporting and recordkeeping requirements.

It is ordered:

1. Late filed comments are hereby accepted and made part of the record in this proceeding.

2. Requests for an opportunity to file reply comments are hereby denied;

3. Requests for a technical conference are hereby denied;

4. In consideration of the foregoing, the Commission amends Part 141 in Chapter I, Title 18, Code of Federal Regulations, as set forth below.

Part 141 - Statement and Reports (Schedules)

1. The authority citation for Part 141 is revised to read as follows:

Authority: 15 U.S.C. 79, 16 U.S.C. 791a-828c, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

2. Section 141.51 is revised to read as follows:

§ 141.51 FERC Form No. 714 Annual Electric Control and Planning Area Report.

(a) Who must file. (1) Any electric utility, as defined by section 3(4) of the Public Utility Regulatory Policies Act, 16 U.S.C. 2602, operating a control area, and any group of electric utilities, which by way of contractual arrangements operates as a single control area, must complete and file the applicable schedules in FERC Form No. 714 with the Federal Energy Regulatory Commission.

(2) Any electric utility, or group of electric utilities that constitutes a planning area and that has a peak load greater than 200 megawatts (MW) based on net energy for load for the reporting year, must complete applicable schedules in FERC Form No. 714.

(b) When to file. FERC Form No. 714 must be filed on or before each June 1 for the preceding calendar year.

(c) What to file. An original and three conformed copies of FERC Form No. 714 "Annual Electric Control and Planning Area Report," must be filed with the Federal Energy Regulatory Commission, in accordance with the instructions in that form and

in this section.

3. Part 141 is amended by adding § 141.300 to read as follows:

§ 141.300 FERC Form No. 715, Annual Transmission Planning and Evaluation Report.

(a) Who must file. Any transmitting utility, as defined in § 3(23) of the Federal Power Act, that operates integrated (that is, non-radial) transmission facilities at or above 100 kilovolts must complete FERC Form No. 715.

(b) When to file. FERC Form No. 715 must be filed on or before each April 1.

(c) What to file. FERC Form No. 715 must be filed with the Federal Energy Regulatory Commission in accordance with the instructions on that form.

Appendix A

Note: Page 1 left blank

Form Approved
OMB No. 1902-0167
Expires: 12/31/96

[Note: The instructions for filling out FERC Form No. 15 appear in appendix A. The changes to FERC Form No. 714 appear in appendix B. Neither appendix will appear in the Code of Federal Regulations]

ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT
FERC Form No. 715

This report is mandatory under Sections 213(b), 307(a) and 311 of the Federal Power Act and Volume 18 C I R Section 141.300.

The Commission does not consider the information collected by this report to be confidential and will not treat it as such.

The public reporting burden for this collection of information is estimated to average 200 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to:

Federal Energy Regulatory Commission
Information Services Division
ED12.3
941 N. Capitol St. N.E.
Washington, D.C. 20426

and to:

Office of Information and Regulatory Affairs
Office of Management and Budget
Washington, D.C. 20503.

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INSTRUCTIONS FOR COMPLETING THE FERC FORM NO. 715
ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

GENERAL INFORMATION

I. Purpose of Report
The FERC Form No. 715, Annual Transmission Planning and Evaluation Report, is required pursuant to Sections 213(b), 307(a) and 311 of the Federal Power Act to provide information adequate to inform potential transmission customers, State regulatory authorities and the public of potential transmission capacity and known constraints, to support the Commission's expanded responsibilities under §§ 211, 212 and 213(a) of the Federal Power Act (as amended by the Energy Policy Act), and to assist in rate or other regulatory proceedings.

II. Who Must Submit
Each transmitting utility, as defined in section 3(23) of the Federal Power Act, that operates network (that is, non-radial) transmission facilities at or above 100 kilovolts must report and make readily available to the public the information requested under the listed items in the prescribed manner. A designated agent, such as a regional transmission group, North American Electric Reliability Council (NERC), regional reliability council, formal power pool, or other group, may submit and make readily available to the public part or all of the required information on behalf of the transmitting utility. The transmitting utility is responsible for submitting all data not submitted on its behalf by a designated agent. Designated agents must specify the transmitting utility (or transmitting utilities) for which they are submitting information.

III. Where to Submit

Submit one original and two copies in hard copy of FERC Form No. 715, Annual Transmission Planning and Evaluation Report, and one copy in electronic form of FERC Form No. 715, Annual Transmission Planning and Evaluation Report (except Part 3: Transmitting Utility Maps and Diagrams), to:

Office of Electric Power Regulation
Federal Energy Regulatory Commission
Room 2410, ER-10 1
825 North Capitol Street N.E.
Washington, D.C. 20426

IV. When to Submit

File the report annually on April 1.

V. Further Information

Direct questions concerning the FERC Form No. 715, Annual Transmission Planning and Evaluation Report, to James S. Ballard at (202) 208-6989, Fax (202) 208-0180.

VI. Sanctions and Confidentiality Statements

The FERC Form No. 715, Annual Transmission Planning and Evaluation Report, is mandatory under the Federal Power Act. The information reported in FERC Form No. 715 is not confidential. Late filing or failure to file, keep records, or comply with these instructions may result in criminal fines, civil penalties, and other sanctions as provided by law.

GENERAL INSTRUCTIONS

The Federal Energy Regulatory Commission (Commission) has determined that to satisfy section 213(b) of the Federal Power Act (FPA) it is necessary for potential customers to be able to reasonably anticipate the outcome of technical studies that a transmitting utility would perform in assessing the availability of transmission capacity to satisfy a request for transmission service. Therefore, the Commission requires each transmitting utility, or its designated agent, to: (1) submit and make available expeditiously to the public, upon request (in hard copy and in electronic form, except for item (b), below) an annual report that includes (a) power flow base cases for its transmission system, or if the transmitting utility belongs to a regional or subregional transmission planning or reliability organization, power flow base cases for that region or subregion; (b) system maps and one-line diagrams; (c) a description of their reliability criteria and transmission planning assessment practices; and (d) an evaluation under the reliability criteria of the current and future performance of their transmission system; and (2) designate any regional or subregional transmission planning or reliability organizations to which it belongs or any other single entity to submit to the Commission and to release to the public any regional or subregional power flow base cases developed for the purposes of members' transmission planning. If Respondents desire to impose copying charges, they shall provide a fee schedule for making this information available to the public.

The Commission assumes that most transmitting utilities participate in the development, by a regional or subregional organization to which they belong, of regional or subregional power flow base cases. The purpose of this process is to ensure consistency of assumptions and accuracy of data.

Individual members of regional or subregional organizations use these power flow cases as the starting place for their own

transmission planning studies. A detailed description of a transmitting utility's reliability criteria and planning

practices and an evaluation of system performance are essential to perform planning studies, to assess the availability of

transmission, to identify potential constraints, and to anticipate the outcome of transmitting utility technical studies

made in response to an actual request for service.

TERMS AND DEFINITIONS

Transmission Planning Reliability Criteria - The measuring systems and performance standards used for assessing the actual

or projected ability of the bulk electric transmission system to deliver power to load reliably. Failure to attain a specified

performance standard indicates the need to consider adding or rearranging facilities, changing operating modes, or other

responses.

Examples of criteria that might apply to simulated testing of the bulk electric transmission system are:

a) No cascading outage following any specified set of contingencies.

b) No overloaded facilities following a specified contingency.

c) All voltages within prescribed limits.

Transmitting Utility - Any electric utility, qualifying cogeneration facility (section 3(18)(B), FPA), qualifying small

power production facility (section 3(17)(C), FPA), or Federal power marketing agency (section 3(19), FPA) that owns or operates

electric power transmission facilities that are used for the sale of electric energy at wholesale. (section 3(23), FPA)

SPECIFIC INSTRUCTIONS

Part 1: Identification and Certification

Provide the following information:

1. Transmitting Utility Name
2. Transmitting Utility Mailing Address
3. Contact Person Name
4. Contact Person Title
5. Contact Person Telephone Number
6. Contact Person Facsimile Number
7. Certification by an authorized official of the Transmitting Utility regarding the accuracy of the information submitted.
8. Certifying Official Signature
9. Certifying Official Name
10. Certifying Official Title

SPECIFIC INSTRUCTIONS (CONT.)

Part 2: Power Flow Base Cases

A Respondent participating in a regional or subregional process (for consolidating and ensuring the consistency and accuracy of the power flow information used by the Respondent for transmission planning) must either authorize the regional or subregional organization to release, without conditions, to the public in an easily accessible electronic format, the most current regional or subregional input data to solved power flow base cases that the transmitting utility would ordinarily use as the starting point for its transmission planning studies or, where these data are unavailable from a regional organization, submit such data itself.

If the Respondent participates in such a regional or subregional process, it must submit the following items:

1. Regional or subregional organization name;

2. Regional or subregional organization mailing address;

3. Regional or subregional organization contact person;

4. Regional or subregional organization contact person title;

5. Regional or subregional organization contact person telephone number;

6. Regional or subregional organization contact person facsimile number;

7. Description of process for public access to regional or subregional power flow information; and

8. Description of power flow cases currently available from regional or subregional organization, including time frame, conditions, format, media and the fees, if any, for copying data for the public.

If a Respondent does not participate in the development of regional or subregional transmission planning power flow base cases, the Respondent must submit its own equivalent power flow base cases directly to the Commission.

SPECIFIC INSTRUCTIONS (CONT.)

Each Respondent must submit for each solved power flow base case: the input data file (in formats described below) and the corresponding output data file (in ASCII format) showing the solved real and reactive power flows, voltages, real and reactive generation and loads, solution parameters, and other relevant output information; or, in the alternative, at a minimum, a one-line diagram showing real and reactive power flows, bus voltages and angles, generator outputs, transformer tap settings and loads.

Regional and subregional organizations authorized by their members to provide access to solved power flow cases should make them available electronically on MS/PC DOS format (version 3.x or higher), high density (1.44 MB), 3.5 inch diskette or via a computer bulletin board, when practical, in the input data format associated with the power flow program that the regional or subregion organizations use in their transmission studies. The Commission expects that, in nearly all cases, the format will be one of the following:

- The Raw Data File format of the PTI (Power Technologies, Inc.) PSS/E Power flow program.

- The Card Deck Image format of the Philadelphia Electric Power flow program.

- The Card Deck format of the WSCC Power flow program.

- The Raw Data File format of the EPC (Electric Power Consultants, Inc.), or the PSLF power flow program.

- The IEEE Common Format for Exchange of Solved Power Flows.

Respondents submitting their own cases must supply the input data to the solved base cases and associated ASCII output data on MS/PC DOS format (version 3.x or higher), high density (1.44 MB), 3.5 inch diskette in the format associated with the power flow program used by the Respondents in the course of their transmission studies, as described above.

The input data to the solved power flow base cases must be forward-looking. For example, the power flow base cases submitted and made available might include:

SPECIFIC INSTRUCTIONS (CONT.)

- One, two, five and ten-year forecasts under summer and winter peak conditions.
- A one-year forecast under light load heavy transfers condition.

This example is similar to a schedule of base cases proposed by NERC's Multiregional Modeling Working Group for development at the time this form was created. A regional or subregional organization may develop, depending on its needs, a different number of power flow base cases than those described above.

The power flow base cases must be in sufficient detail that network equivalents, if used, extend sufficiently beyond the electrical borders of the transmitting utility that potential transmission users could simulate power transfers within a reasonable market area without significant loss of accuracy.

The power flow base cases should include all branch circuit ratings (that is, normal, long-term and short-term emergency, or other relevant ratings) that a Respondent uses. Each Respondent must also submit or make available a data-dictionary that cross-references the bus or line terminal names.

SPECIFIC INSTRUCTIONS (CONT.)

Part 3 Transmitting Utility Maps and Diagrams

1. Each Respondent must submit an original and one copy of general transmission maps and single-line schematic diagrams. The maps and diagrams should be those prepared in the general course of business for planning and operating purposes. The guidelines provided below indicate the type of information and the level of detail desired, however, the Commission is not requiring the Respondent to specifically prepare new maps and diagrams to satisfy this requirement. If the Respondent has readily available more than one set of maps and/or diagrams, the Commission requests that the set submitted best provide the level of detail described below.

2. The transmitting utility's general maps should show the geographic locations and names of:

   A. Generating plants;
   B. Switching stations;
   C. Substations;
   D. Service areas; and
   E. Interconnections with other utilities.

3. The transmitting utility's single-line schematic diagrams should show and identify:

   A. AC and DC transmission lines and facilities, including their nominal operating and design voltages,;

   B. Electrical connections;
   C. Generating plants;

   D. Transformation facilities;
   E. Phase angle transformers;

   F. VAR control equipment; (i.e., shunt and series capacitors and inductors, etc).

4. On the maps or in separate documentation, each Respondent should provide a legend that shows the symbols used on the map or diagram to represent generators, transmission lines, transformers, capacitors, reactors, buses, etc.

SPECIFIC INSTRUCTIONS (CONT.)

5. If maps and diagrams have not changed from those currently on file at the Commission, Respondents should make a statement to that effect. Respondents must submit new maps or diagrams only if they have revised those currently on file at the Commission.

SPECIFIC INSTRUCTIONS (CONT.)

Part 4 Transmission Planning Reliability Criteria

Each Respondent is to provide the transmission planning reliability criteria used to assess and test the strength and limits of its transmission system to meet its load responsibility as well as to move bulk power between and among other electric systems.

If a Respondent subscribes to the NERC and regional reliability council transmission reliability criteria, the Respondent must submit the documents containing such criteria, unless these documents are readily available in NERC publications or are available in the regional reliability council OE-411 reports submitted to the DOE. In such cases, Respondent must submit only the title, source and effective date of each publication or document.

If a transmitting utility subscribes to more detailed criteria compatible with the NERC or regional reliability council through its interconnection or pooling agreements with others, then it must also submit these additional criteria.

The Commission expects that each transmitting utility will have additional detailed criteria. For example, each utility generally sets its own voltage limit criteria on its bulk system as well as its lower voltage system, since NERC and the regional reliability councils generally do not. Particular criteria may differ from those of the council and may be justified by the geography of the area, type of loads being served, system configuration, weather considerations, or other reasons. Each transmitting utility must submit all such additional criteria.

The above criteria will be those which the transmitting utility uses to determine available transmission capacity needed to meet potential transmission requests as well as its own native load. A transmitting utility must describe the criteria that it uses in sufficient detail to allow others to use the criteria when performing their own planning or screening studies and to better understand the process of determining available transmission capacity.

In subsequent years, Respondents need only identify and file changed criteria.

SPECIFIC INSTRUCTIONS (CONT.)

Part 5 Transmission Planning Assessment Practices

The criteria submitted under Part 4 of this form set the limits of transmission use. However, assessment practices that a transmitting utility uses in applying these criteria are as important as the criteria themselves. These practices, developed through experience and study, include consideration of detailed factors that a transmitting may not list in the criteria that it submits under Part 4. For example, a utility might have certain operating restrictions and limitations that must be met by appropriate modelling within a simulation study.

Also, through experience and study, each transmitting utility may have developed a list of various contingencies it typically tests against in the application of its transmission planning reliability criteria. For example, before testing for the limits of transmission capability that could be used for firm power transfers on its system, a transmitting utility will assume, based on experience or realistic expectation, that certain facilities will be unavailable for some period of time. Each transmitting utility must identify these contingencies and submit them under this Part.

A description of the Respondent's practices when applying the transmission planning reliability criteria submitted in Part 4 must be submitted under this part. The description must include the substantive planning assessment practices that a Respondent follows in the normal course of business. The information filed should help requesters to perform planning or screening studies and to better understand the process of determining available transmission capacity and known constraints.

In subsequent years, Respondents need only identify and file changed assessment practices.

SPECIFIC INSTRUCTIONS (CONT.)

Part 6 Evaluation of Transmission System Performance

The transmitting utility must provide a narrative evaluation or assessment of the performance of its transmission system in future time periods based on the application of its reliability criteria. It must provide a clear understanding of existing and likely future transmission constraints, their sources, how it identified these constraints, and a description of any plans to mitigate the constraints. The evaluation must provide a clear understanding of the existing and expected system performance of the Respondent's transmission system. The evaluation should include a description of all existing transmission stability limits that the transmitting utility has uncovered through dynamic system simulation studies. If, in their studies, Respondents identify stability as a regional transmission limiting factor, Respondents must, on request, provide the results of their studies.

The required evaluation is to be drawn from existing utility transmission planning studies and the experience and judgment of the Respondents' transmission system planners. Respondents may base the required evaluation, in part, on recently performed operating studies that determine transfer capabilities for the upcoming peak load season.

Changes to FERC Form No. 714

The existing form FERC-714 is modified by eliminating Schedules VIII, XIII, XIV and XV, modifying Schedules VI and VII and consolidating Schedules X, XI, and XII. The table of contents (reorganized and renumbered) is as follows:

Part I: Identification and Certification

Part II: Control Area Information
Schedule 1: Generating Plants Included in Reporting Control Area
Schedule 2: Control Area Monthly Capabilities at Time of Monthly Peak Demand
Schedule 3: Control Area Net Energy for Load and Peak Demand Sources by Month
Schedule 4: Adjacent Control Area Interconnections

Schedule 5: Control Area Scheduled and Actual Interchange
Schedule 6: Control Area Hourly System Lambda

Part III: Planning Area Information
Schedule 1: Electric Utilities that Compose the Planning Area

Schedule 2: Planning Area Hourly Demand and Forecast Summer and Winter Peak Demand and Annual Net Energy For Load

Part IV: Notes

The existing Schedule VII, Control Area System Lambda is replaced by the following:

Part II Schedule 6: Control Area Hourly System Lambda

Submit on a 3.5 inch diskette formatted for the DOS operating system the following data file in ASCII format: the control area's system lambda for each hour of the year starting with 1 a.m., January 1, 1993. Identify clearly the time zone in which this time series is made. The file should have 8760 records (8784 for leap years). Each record is to contain the system lambda value at the clock hour in dollars per megawatthour (mills per kilowatthour) or an "NA" for those hours when system lambda was not calculated.

Control Area Hourly System Lambda. For control areas where demand following is primarily performed by thermal generating units, the system lambda is derived from the economic dispatch function associated with automatic generation control performed at the controlling utility or pool control center. Excluding transmission losses, the fuel cost ($/hr) for a set of on-line and loaded thermal generating units (steam and gas turbines) is minimum 1/ when each unit is loaded and operating at the same incremental fuel cost ($/MWh) 2/ with the sum of the unit loadings (MW) equal to the system demand plus the net of interchange with other control areas. This single incremental cost of energy is the system lambda. System lambdas are likely recalculated many times in one clock hour. However, the indicated system lambda occurring on each clock hour would be sufficient for reporting purposes.

Provide, as a note in Part IV, an explanation describing the reason for the unavailability of system lambda information and a definite plan for reporting the information with a target date. The Commission expects that all Energy Management Systems, with proper instructions, can record the system lambda being used for economic dispatch of the control area's thermal units.

1/ Some utilities may also include variable operation and maintenance costs that they consider "dispatchable." Therefore the costs to be minimized could include a variable O&M component as well as the fuel costs.

2/ Because unit heat rates and fuel costs vary, some units may not be able to operate at the same incremental fuel cost as the other units and, thus, those units may be loaded differently.

Respondents should be able to report system lambda, along with the other information reported on a control area basis, that describe the operation of such areas from information that should be readily available. The Commission is not requesting Respondents to develop incremental or marginal cost (either short or long term) according to any formula. Nor is the Commission requesting "avoided cost rates" that, pursuant to PURPA 210, electric utilities file with state commissions or otherwise make available for prospective qualified facilities.

Description of Economic Dispatch. Also, provide in writing a detailed description of how Respondent calculates system lambda. For those systems that do not use an economic dispatch algorithm and do not have a system lambda, provide in writing a detail description of how control area resources are efficiently dispatched.

The existing Schedule X, Planning Area Monthly Net Energy for Load, Schedule XI Planning Area Summer and Winter Actual and Peak Demand and Annual Net Energy for Load, and Schedule XII, Planning Area Hourly Demand Data By Specified Week are replaced by the following:

Part III Schedule 2: Planning Area Hourly Demand and Forecast Summer and Winter Peak Demand and Annual Net Energy For Load

(1) Respondents must submit hourly demand data in electronic form to the Commission. Additionally, Respondents that participate in a national, regional or subregional process for consolidating and ensuring the consistency and accuracy of actual hourly and forecast demand information, may instead authorize the national, regional or subregional organization to release that information to the Commission, and to the public at the cost of reproduction, in an easily accessible electronic format, such as EEI format.

(2) If the Respondent does not participate in the development of national, regional or subregional actual and forecast demand information, it must submit its own, equivalent, demand information directly to the Commission along with this report, as follows.

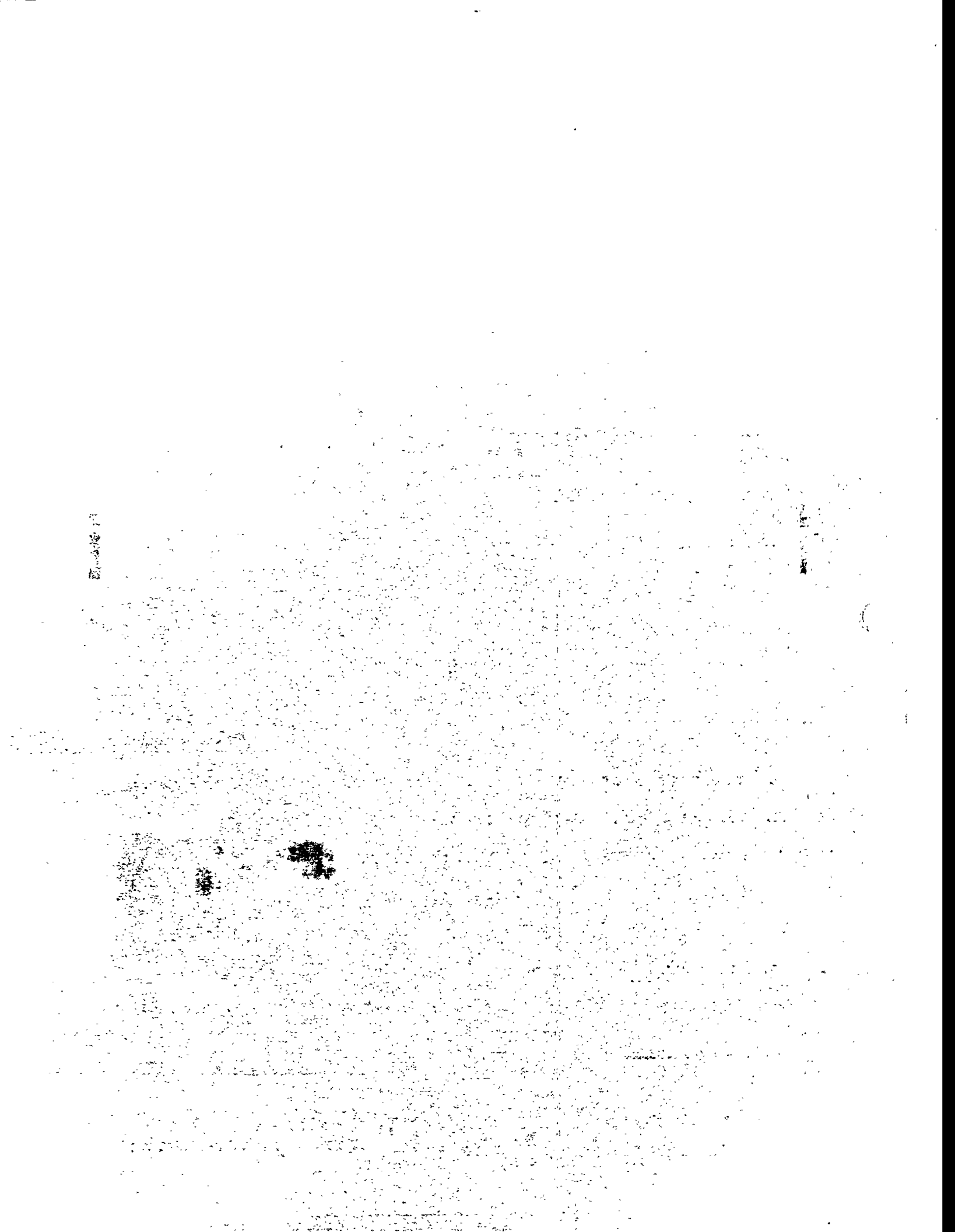
Respondents must submit on a 3.5 inch diskette formatted for the DOS operating system the following data file in ASCII format: the planning area's actual hourly demand, in megawatts, for each hour of the year starting with 1 am, January 1, 1993, central standard time. The file should have 8760 records (8784 for leap years). For hours when this information is not available, enter "NA."

Also provide on the diskette a file containing the planning area's forecast summer and winter peak demand, in megawatts, and annual net energy for load, in megawatthours, for the next ten years.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Acting Secretary.



UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act	)))))	Docket No. RM93-19-000

NOTICE OF TECHNICAL CONFERENCE AND REQUEST FOR COMMENTS

(June 30, 1993)

I. INTRODUCTION

The Federal Energy Regulatory Commission (Commission) is initiating this proceeding to consider whether it is appropriate to revise the Commission's present pricing policy for transmission services provided by public utilities 1/ under the Federal Power Act (FPA).

Attached to this notice is a discussion paper prepared by the Commission staff setting forth staff's preliminary observations on transmission pricing issues. 2/

Historically, the Commission has permitted public utilities providing firm transmission service over an integrated transmission grid to charge rates reflecting the rolled-in embedded cost of the integrated grid, including the rolled-in

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1/ 16 U.S.C. 824(e).

2/ The staff discussion paper is not being published in the Federal Register, but is available through the Commission's Public Reference Section.

Dorn Systems Corporation, also located in Room 3104, 941 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

James H. Douglass
Office of the General Counsel
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426
Telephone: (202) 208-2143
(legal issues)

Stephen J. Henderson
Office of Economic Policy
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426
Telephone: (202) 208-0100
(technical issues)

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in Room 3104, at 941 North Capitol Street, N.E., Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing (202) 208-1397. To access CIPS, set your communications software to use 300, 1200, or 2400 bps, full duplex, no parity, 8 data bits and 1 stop bit. CIPS can also be accessed at 9600 bps by dialing (202) 208-1781. The full text of this order will be available on CIPS for 30 days from the date of issuance. The complete text on diskette in WordPerfect format may also be purchased from the Commission's copy contractor, La

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Chapter I

[Docket No. RM93-19-000]

Inquiry Concerning the Commission's Pricing Policy
for Transmission Services Provided by Public Utilities
Under the Federal Power Act

NOTICE OF TECHNICAL CONFERENCE AND REQUEST FOR COMMENTS

(June 30, 1993)

AGENCY: Federal Energy Regulatory Commission

ACTION: Notice of Technical Conference and Request for Comments

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing this notice to request comments concerning whether it is appropriate to revise the Commission's present pricing policy for transmission services provided by public utilities under the Federal Power Act.

DATES: Written comments must be received by the Commission on or before [insert date that is 60 days after this notice is published in the Federal Register]. Reply comments must be received no later than 30 days after the date that initial comments are due. Notice of the technical conference will be published in the Federal Register at a later date.

ADDRESSES:

Send Comments to:

Office of the Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

costs of any new facilities or upgrades which become part of the integrated grid. 3/ The Commission has also historically designed firm (and non-firm) transmission rates on a "postage stamp" basis. 4/

As described more fully in the staff paper, the Commission has modified its historic, rolled-in embedded cost pricing policy in the last two years. 5/ Under the revised policy, when a utility chooses to add new capacity to relieve a transmission constraint, the Commission allows the utility the option of charging the higher of an embedded cost rate (calculated to include the rolled-in costs of the added facilities) or a rate

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3/ In certain circumstances, the Commission has permitted public utilities to charge rates reflecting a share of the savings based on the difference between the seller's incremental generation costs and the buyer's decremental generation costs. See Southern Company Services, Inc., 37 FERC ¶ 61,190 (1986).

4/ Postage stamp rates are based on the theory that, when a utility provides transmission service, it uses its entire integrated transmission grid to provide the service. As such, postage stamp rates do not vary based on the length of transmission provided; in other words, it costs the same amount to move 1 MW of power 10 miles as it does to move it 100 miles.

5/ Northeast Utilities Service Company (Re Public Service Company of New Hampshire), Opinion No. 364-A, 58 FERC ¶ 61,070, reh'g denied, Opinion No. 364-B, 59 FERC ¶ 61,042, order granting motion to vacate and dismissing request for rehearing, 59 FERC ¶ 61,089 (1992), affirmed in part and remanded in part sub nom. Northeast Utilities Service Company v. FERC, Nos. 92-1165, et al. (1st Cir. May 19, 1993) (NU); Pennsylvania Electric Company, 58 FERC ¶ 61,278, reh'g denied and pricing policy clarified, 60 FERC ¶ 61,034, reh'g rejected, 60 FERC ¶ 61,244 (1992), appeal pending, No. 92-1408 (D.C. Cir. filed Sept. 11, 1992) (Penelec).

based on the incremental cost of expansion. 6/ In situations in which a utility chooses not to add new capacity to relieve a transmission constraint, the Commission allows the utility the option of charging the higher of an embedded cost rate or a rate based on opportunity costs 7/ capped at the incremental cost of expansion. The Commission also has made clear that, in addition to an embedded cost rate or an incremental cost rate, a utility may also charge for the costs associated with interconnecting a particular customer or building a radial line between the customer and the utility's transmission system when such a line is not integral to the utility's system. 8/

The Commission's revised pricing policy for firm transmission service has generated considerable controversy and

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6/ The First Circuit stated in NU:

> Under "rolled in" pricing principles, the upgrade costs would be rolled in with other company costs and charged to all ratepayers as part of [a utility's] general rate structure; while administratively simple, it ignores any concept of responsibility. Thus, incremental pricing principles look to hold parties responsible for their share of upgrade costs.

NU, supra, slip op. at 44 n.17, ___ F.2d ____ (1st Cir. 1993).

7/ The Commission has stated that opportunity costs, "generally are incurred by a utility when the utility accommodates a third party's request for transmission service (i.e., wheeling request) and thereby forgoes an opportunity to reduce its own costs, to the economic detriment of the utility's native load customers." Penelec, 58 FERC at 61,871.

8/ See NU, slip op. at 44, 45 n.18, ___ F.2d ____ (1st Cir. 1993); Penelec, 60 FERC at 61,129-2 n.49.

debate in the electric utility industry. Various interest groups hold widely divergent views as to the appropriate pricing approach, e.g., concerning distance sensitivity, parallel path and loop flow issues, and spot pricing.

There is also disagreement concerning the Commission's pricing policy for non-firm transmission service. Historically, the Commission has permitted non-firm transmission rates to reflect up to a 100% contribution to the fixed costs of providing the service, with the proviso that pricing must reflect the attributes of the service provided, i.e., the degree of firmness. 9/

Given the dramatic changes which the electric industry has faced, and will face in the near term, there can be no dispute that transmission availability and pricing are among the most important policy issues the Commission will face in the coming decade. Such changes include: increased reliance on market forces to meet power supply needs; new market entrants such as exempt wholesale generators; a significant number of utility mergers and combinations; more highly integrated operation of various power pools; and substantial bulk power trading among electric systems. In addition, many public utilities have filed, or are considering filing, open access transmission tariffs under

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9/ New England Power Company, Opinion No. 335, 49 FERC ¶ 61,129 (1989), reh'g denied, Opinion No. 335-A, 50 FERC ¶ 61,151 (1990), aff'd, No. 90-1179 (D.C. Cir. Feb. 11, 1991) (unpublished).

Section 205 of the FPA. Further, Congress has given the Commission new authority under the Energy Policy Act of 1992 10/ to compel transmission service under certain circumstances if the Commission determines that such transmission is in the public interest and does not unreasonably impair reliability. As a result, transmission rate schedules will be filed pursuant to orders issued under amended FPA section 211. These open access tariffs and rate schedules will provide more opportunities for buyers and sellers to participate in larger geographic markets. These changes underscore the importance of ensuring that our transmission pricing policies promote efficiency, encourage access, and reflect a reasonable allocation of costs.

In these circumstances, the Commission believes that it is now appropriate to examine its present transmission pricing policy to determine if the present policy promotes or discourages efficiency and competition in the wholesale electric market. Accordingly, the Commission invites comments on, and will hold a technical conference on, whether the present pricing policy needs revision, and possible alternative pricing models.

Clearly, any transmission pricing model adopted by the Commission must meet the substantive standards contained in the FPA. Rates for transmission service under section 205 of the FPA must be just and reasonable and not unduly discriminatory or preferential. Rates for transmission service under section 211

10/ Pub. L. No. 102-486, 106 Stat. 2776 (1992).

of the FPA must meet the requirements of section 212(a) of the FPA, as added by the Energy Policy Act. Such rates must: (1) allow the transmitting utility to recover all the costs incurred in connection with the transmission services and necessary associated services including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities; (2) promote the economically efficient transmission and generation of electricity; (3) be just and reasonable, and not unduly discriminatory or preferential; and (4) ensure, to the extent practicable, that costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for service and not from a utility's existing wholesale, retail and transmission customers.

Whether the Commission ultimately decides to retain its present transmission pricing policy, or to adopt a new pricing policy, it will ensure that these substantive legal standards are met. The Commission also invites comments on the scope of the Commission's discretion on transmission pricing under section 212 of the FPA, and on whether the Commission should apply the same pricing under section 205 of the FPA as it applies under section 212.

The Commission invites comments on these issues and on the analyses presented in the attached staff paper, and encourages commenters to present their own suggestions concerning alternative transmission pricing models. The discussion paper is intended to initiate discussion and highlight the scope of this inquiry. It is not intended to limit the dialogue. 11/

In undertaking this inquiry, the Commission recognizes that pricing is only one aspect of ensuring meaningful transmission access and fostering workable competition in the wholesale bulk power market. Other initiatives are currently being considered by the Commission or have already been undertaken. 12/ Certain of these initiatives are a direct result of the Energy Policy Act. Others arise as side issues which will require careful consideration. For example, the Commission will face issues such as what are the appropriate "non-price" terms and conditions of transmission service as well as what constitutes a

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11/ Some of the materials referenced in the discussion paper will be placed in the Commission's public files in this proceeding and will be available for inspection at the Commission's Public Reference Section, Room 3408, 941 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

12/ Earlier this year, the Commission issued a final rule regarding certification of Exempt Wholesale Generators. [Order No. 550 FERC Statutes and Regulations ¶ 30,964; Order No. 550-A, FERC Statutes and Regulations ¶ 30,969 (1993)] On March 30, 1993, the Commission issued a Notice of Proposed Rulemaking dealing with the transmission information requirements of section 213(b) of the FPA. [FERC Statutes and Regulations ¶ 32,493 (1993)]. The Commission has also requested public comment on the issue of Regional Transmission Groups based upon a consensus proposal which was not included in the Energy Policy Act. [61 FERC ¶ 61,232 (1992)].

"good faith" transmission request and reply. The Commission will also face issues regarding the provision of ancillary services, reliability concerns, and determinations of adequate transfer capability. In addition, the Commission recognizes that state regulatory commissions have substantial jurisdiction over transmission facilities. Indeed, transmission facilities are used predominantly to provide service to retail consumers and these facilities are included in retail rate base. Furthermore, most states have siting authority with regard to transmission construction. Consequently, many of the pricing reforms contemplated by this inquiry may implicate state/Federal jurisdictional issues.

We wish to assure commenters that we recognize the spectrum of transmission issues and that we fully intend to address all such issues, whether on a generic basis, or as part of our adjudicative function. Today, we nonetheless have purposefully limited the focus of this inquiry to technical issues related to transmission pricing and certain related legal questions.

II. PUBLIC COMMENT PROCEDURES

The Commission invites all interested persons to submit an original and 14 copies of their written comments. Technical and policy comments on pricing should not exceed 50 pages in length. Comments on legal issues should be submitted in a separate document and should not exceed 25 pages in length. In addition, commenters should submit an executive summary of each set of comments, not to exceed five pages.

The Commission will also permit interested persons to submit reply comments in response to the initial comments filed in this proceeding. Reply comments should not exceed 25 pages in length and should be submitted no later than 30 days after the date that initial comments are due. If reply comments address both technical/policy issues and legal issues, the comments must be divided into two separately labeled sections.

Persons with common interests or views are encouraged to submit joint comments. Commenters should double space their comments, provide a concise description identifying the commenter, and should reference Docket No. RM93-19-000. In addition, commenters should submit a copy of their comments on a 3 1/2 inch diskette in ASCII II format. Initial comments must be filed with the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than [insert date 60 days after publication of this notice in the Federal Register].

All written comments will be placed in the Commission's public files and will be available for inspection at the Commission's Public Reference Section, Room 3408, 941 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

A technical conference to discuss transmission pricing issues will be scheduled on a date to be established after the Commission has had an opportunity to review the comments. The Commission invites interested persons to file requests to

participate in the technical conference. Requests must be in writing and submitted to the Office of the Secretary no later than the date that comments are due. Persons with common interests or views are requested to file joint requests for participation, so that the Commission can accommodate the maximum number of participants. When the Commission issues a subsequent notice specifying the date, time and place for the technical conference, the Commission will identify the agenda for the conference (including format) and the persons who have been selected to participate.

By direction of the Commission.

(S E A L)

Lois D. Cashell

Lois D. Cashell,
Secretary.

NOTE: THIS PAPER WILL NOT BE PUBLISHED IN THE FEDERAL REGISTER

STAFF DISCUSSION PAPER
Transmission Pricing Issues

The Commission is interested in engaging in a broad discussion of transmission pricing reform. This paper sets out major pricing issues that confront the electricity industry. The discussion here reflects the dialogue that has begun within the industry. The Mid-Continent Area Power Pool (MAPP) has recently initiated a re-examination of transmission pricing, including alternatives that would explicitly account for distance in developing transmission rates. The General Agreement on Parallel Paths (GAPP), which is a committee of the Interregional Transmission Coordination Forum, is engaged in a discussion of parallel-path/distance-sensitive pricing concepts. The New England Power Pool has examined transmission pricing issues as part of its Regional Transmission Association discussions. In addition, advanced models of spot transmission pricing, as discussed below, have been developed to the point where serious consideration is warranted. Thus, it is appropriate for the Commission to engage in this inquiry at this time.

Transmission pricing has multiple policy dimensions which will involve important tradeoffs. For example, it is important to provide transmission price signals that accommodate the efficient operation of existing generating plants while also encouraging least cost investment in new plants. At the same time, any pricing reform must also be fair and equitable to existing and new users of the grid. More precise cost measurement is a reasonable goal, but the result should not be overly complex to implement. The Commission must weigh these competing considerations and decide whether reform is appropriate and, if so, how extensive any reform should be. Reform, however, should not be sought for its own sake. Pricing policy changes are appropriate only if they enable the industry to improve its performance at a reasonable cost of implementation. The threshold issue, then, is whether the benefits of changing our existing transmission pricing policy outweigh the costs.

This paper first reviews the Commission's traditional approach to transmission pricing and recent developments that have led to this inquiry. This is followed by a short discussion of the scope of the inquiry in order to focus comments on certain major issues. Included in this discussion is a short list of suggested criteria for evaluating alternative pricing options. The next three sections discuss specific pricing issues that have triggered proposals for reform.

I. BACKGROUND

A. The Commission's Traditional Approach to Transmission Pricing

Historically, the Commission has based its approach to transmission pricing on the rolled-in, average historic costs of the transmitting utility (including those of any affiliates, in the case of holding companies). This precedent was largely developed for requirements

service where the wholesale customer's load is dispersed throughout the utility's service territory and integrated generation and transmission facilities are used. The result has been a "postage stamp" rate, *i.e.*, a unit charge for moving a unit of electricity over the transmitter's grid that does not recognize whether the electricity is transmitted 10 miles or 200 miles. 1/

The Commission has supported the postage stamp method for cost recovery on the grounds that a transmitter's grid is an integrated whole. That is, the Commission has approved single, rolled-in transmission rates because a corporate entity, the transmitting utility, operates its grid in a single, unified way. Such integrated operation complicates the issue of establishing cost responsibility. In addition, the benefits of reliable operation are difficult to separate and quantify in such an integrated system. By averaging system transmission costs and recovering them from all uses of the system, postage stamp rates have the practical virtue of administrative simplicity.

However, postage stamp rates may have important limitations, particularly in providing price signals to transmission users. Such rates may not reflect the cost of scarcity when there is a bottleneck on the grid, the costs of expanding capacity to remove such a bottleneck, or the cost of transmitting power over long distances. Because of the recent enactment of the Energy Policy Act of 1992 (EPAct) and the emerging competition in wholesale power markets, it is now appropriate to reevaluate postage stamp ratemaking.

Utilities transact with one another based on a so-called contract path concept.. Under the contract path concept, all parties assume, for pricing purposes, that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. In reality, however, power flows are rarely confined to a designated contract path. Instead, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being wheeled (or transmitted) from one utility to another to travel along multiple parallel paths and divide itself among those paths along the lines of least resistance. This parallel path flow is sometimes called loop flow.

The industry's contract path approach has been incorporated into the Commission's traditional transmission ratemaking. In effect, the industry has adopted and the Commission has accepted a convenient fiction that power travels along a contract path that differs from

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1/ The term "grid" is used in this paper to mean the interconnected network of high-voltage transmission lines. Facilities that provide no system-wide benefit, *e.g.*, radial lines to remote load or facilities connecting generation facilities to the grid, are not considered part of the grid. Under certain limited circumstances, the Commission has allowed transmitting utilities to assign the capital costs of radial lines directly to specific customers. Where appropriate, such costs can be added to the charge for use of the grid. Central Maine Power Company, 54 FERC ¶ 61,206 at 61,611-12 (1991).

the real physical paths. The result is that some utilities whose transmission facilities are used to carry the power in reality, but who are not part of the contract path, may not be adequately compensated unless they seek compensation in a rate case before the Commission. Under Section 205 of the Federal Power Act, if a utility can demonstrate that others are imposing costs on its transmission system, it can file a separate rate to recover the costs imposed. However, this issue is complex and could require a fairly elaborate evidentiary showing.

The current contract path approach to pricing may or may not continue to be appropriate; however, it is clearly an issue which the Commission wishes to explore. In the past, the mismatch between compensation and actual flows was widely accepted, mostly because the industry believed that the overall costs and benefits were roughly balanced--others carried your power as much as you carried their power. In addition, utilities' planning efforts contributed to this balance by sharing the cost of new facilities or by taking turns in building. However, the mismatch has become more difficult to manage or ignore as power flows have become more unidirectional.

In the past 20 years, for example, the divergence between actual and assumed contract path flows has led utilities to install mechanical devices known as phase shifters in both the Eastern and Western Interconnections. A phase shifter is a device that redirects electrical current on an alternating current (AC) transmission grid. In addition, Western utilities experimented with various compensation mechanisms. Insulated from the other interconnections, utilities in the Electric Reliability Council of Texas (ERCOT), under the leadership of the Public Utility Commission of Texas, have been able to fashion wheeling rates that take account of loop flow. ERCOT's ability to deal with actual, as opposed to contracted, power flows has been successful, in part, because of the limited number of utilities involved.

Even with its limitations, the contract path approach to transmission pricing has served the Nation well. It has accommodated substantial amounts of efficient trading in the industry, all at a reasonable administrative cost. Nonetheless, the drawbacks in that approach are creating increasing stress. The expansion of the grid, regional imbalances in available generation resources and the emergence of competitive power markets are helping to create more transactions with benefits and costs that may not balance out among utilities as they have in the past. For example, bundled transactions involving both generation and transmission were prevalent in the past. Such transactions allow the parties to share the benefits associated with the sale of a bundled generation and transmission service. In contrast, a utility providing unbundled transmission service may be fully compensated for its transmission costs, but it does not receive any share of the possibly much larger benefits associated with the power sale. Accordingly, as the trend toward more unbundled

transmission service continues, 2/ greater pressure will be placed on the Commission to adopt pricing policies that identify transmission costs more accurately, to allocate those costs appropriately, to develop rates that convey good price signals to users, and to develop approaches that fairly distribute benefits.

B. Recent Changes to the Traditional Approach

In the last two years, the Commission has attempted to address the industry's changing needs by modifying its transmission pricing policy in some respects. Incremental cost pricing is an example. Under traditional ratemaking, the addition of new, expensive transmission assets can cause average rolled-in rates to go up. If the Commission were to require a utility to provide transmission service (*e.g.*, as a condition for a merger or market-based pricing) for which an expensive upgrade would be needed, native load rates could increase under rolled-in pricing. As a result, native load customers would pay some part of the wheeling costs caused by the third-party service. The Commission has sought to avoid such an outcome.

The Commission recently revised its pricing policy to address this possibility. The revised pricing model was developed in the *NU* merger case 3/ and in the *Penelec* case. 4/ The model is based on a balancing of three principles:

- Hold native load customers harmless

2/ The Commission has accepted unbundled transmission tariffs from a number of utilities, *e.g.*, Utah Power & Light Company, *et al.*, Opinion No. 318, 45 FERC ¶ 61,095 (1988), *order on reh'g*, Opinion No. 318-A, 47 FERC ¶ 61,209 (1989), *order on reh'g*, Opinion No. 318-B, 48 FERC ¶ 61,035 (1989), *aff'd in relevant part sub nom.* Environmental Action Inc. *et al.* v. FERC, 939 F.2nd 1057 (D.C. Cir. 1991); Entergy Services, Inc., 58 FERC ¶ 61,234 (1992), *order on reh'g*, 60 FERC ¶ 61,168 (1992), *appeal pending sub nom.*, Cajun Electric Power Cooperative, Inc. *et al.* v. FERC, Nos. 92-1461, *et al.* (D.C. Cir. filed Sept. 24, 1992).

3/ Northeast Utilities Service Company, Opinion No. 364, 58 FERC ¶ 61,070 (1992) (hereinafter cited as *NU*), *reh'g denied*, Opinion No. 364-B, 59 FERC ¶ 61,042 (1992), *order granting motion to vacate and dismissing request for rehearing*, 59 FERC ¶ 61,089 (1992), *affirmed in part and remanded in part sub nom.* Northeast Utilities Service Company v. FERC, Nos. 92-1165, *et al.* (1st Cir. May 19, 1993).

4/ Pennsylvania Electric Company, 58 FERC ¶ 61,278(1992) (hereinafter cited as *Penelec*), *reh'g denied and pricing policy clarified*, 60 FERC ¶ 61,034 (1992), *reh'g rejected*, 60 FERC ¶ 61,244 (1992), *appeal pending*, No. 92-1408 (D.C. Cir. filed Sept. 11, 1992).

- Provide the lowest reasonable cost-based price to third-party transmission customers

- Prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions.

From these principles, the Commission has adopted two pricing modifications: (1) incremental cost pricing for grid expansion or upgrades that relieve a constraintand (2) opportunity cost pricing for a change in operations that relieves a grid constraint. A change in operations might require the transmitting utility to run uneconomical generation units (called re-dispatching) or to forego off-system sales or purchases (by curtailing scheduled power transfers). Either operational change could free up transmission capacity for use by a third party, without building new capacity.

In implementing these pricing modifications, the Commission has concluded that third-party rates should be high enough to hold native load harmless. As a result, when the grid is expanded, the Commission's current policy allows a utility to charge third party transmission customers the higher of embedded costs (for the system as expanded) *or* incremental expansion costs, but not the sum of the two. When the grid is constrained but the utility chooses to not expand its system, the Commission allows a utility to charge the higher of embedded costs *or* legitimate and verifiable opportunity costs, but not the sum of the two. The opportunity costs, in turn, are capped by incremental expansion costs. These pricing policies are collectively referred to as the "or" option.

Implementing these policies has been controversial. The Commission's "higher of" policy (i.e., the "or" option) has been opposed by some transmission owners who urge the Commission to allow them to charge third party transmission customers the existing embedded cost rate (without the expansion) *and* to specifically assign any additional incremental costs associated with the transaction to the third party requesting service (i.e., the "and" option). This is now known as the "and/or" pricing issue. 5/

The "or" policy is also opposed by some representatives of the parties that the Commission had intended to protect--the native load. Further, some state regulators believe that the "or" pricing policy is not fully compensatory. 6/ At its core, the and/or issue is

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5/ The controversy was discussed in the Congressional Record accompanying the passage of the EPAct. *See, e.g.*, 138 Cong. Rec. H.11412-13 (daily ed. Oct. 5, 1992); 138 Cong. Rec. S.17612-623 (daily ed. Oct 8, 1992).

6/ As an example, see the resolution passed by the Executive Committee of the National Association of Regulatory Utility Commissioners, *Resolution Encouraging State Regulatory Commissions to Consider Reforming Transmission Pricing Policies for*

(continued...)

whether holding native load customers harmless is enough or whether some additional compensation for transmitters is appropriate. In effect, the Commission's benchmark for "hold harmless" is economic neutrality (prevent native load rates from going up), while some transmission owners and state commissions would prefer the benchmark to be some form of fair compensation for the use of existing facilities plus any expansion or opportunity cost. This argument is raised below as part of the discussion of incentives to provide service under the current pricing approach.

The "or" policy has been criticized on other grounds. The "or" policy allows a transmitting utility to charge an embedded cost price, which it will presumably choose to do, when the incremental cost is lower than the embedded cost. This provision is objectionable to some transmission customers who feel that if they must pay incremental cost when it is higher, they should also receive the benefits of paying the incremental cost when it is lower. Assuming that incremental expansion cost is lower than an embedded cost rate, it can be argued in response that such a policy would allow third parties to pay lower rates when service is constrained than when it is not. In addition, it raises questions about equity to native load customers since third-party rates would be lower than native load rates in such circumstances.

II. SCOPE OF THE INQUIRY

Staff believes that, although the Commission's pricing inquiry should be broad ranging, it must be focused in order to be manageable. To help focus the dialogue, Staff particularly encourages comments on the questions raised in this paper. This is not intended to preclude comments on any other transmission pricing issue that commenters believe warrants the Commission's attention. At a minimum, comments should be identified under one of the following three categories:

- Revisions to the Current Pricing Policy
- Reform of Traditional Ratemaking: Firm Service Pricing Issues
- Reform of Traditional Ratemaking: Non-Firm Service Pricing Issues

Within these categories, we ask specific questions that are designated by number later in this paper. Responses to these questions should be identified by reference to the question number.

The scope of this pricing inquiry is limited in two ways. First, this inquiry is limited to wholesale transmission service. Retail wheeling issues will not be addressed. Second,

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6/(...continued)

Retail Electric Services, adopted March 1993. The resolution encouraged state commissions to consider alternative ways of regulating the transmission function as part of retail service in light of the increasing federal role.

Staff recognizes that State regulatory commissions have substantial jurisdiction over transmission facilities. Indeed, transmission facilities are used to provide service to retail consumers and these facilities are included in the retail rate base. Furthermore, most states have siting authority with regard to transmission construction. While this inquiry is not focused on State-Federal issues relating to transmission pricing, commenters are invited to address such issues to the extent that particular reforms are affected by jurisdictional matters.

As a general matter, Staff notes that many of the issues discussed in this paper also are appropriate subjects for discussions within regional transmission groups. 7/ In many instances, regions would not be expected to adopt a uniform national approach in addressing a particular issue, *e.g.*, loop flow.

Staff believes that, to the extent practicable, the criteria to be used to assess alternative transmission pricing options should be explicit. Among the possible criteria that could be used to evaluate any transmission pricing reform are the following:

- Promote efficient use of and investment in the transmission grid and provide appropriate price signals to transmission customers. To the extent practicable, prices should accurately:
  - ▸ account for transmission constraints
  - ▸ reflect any prudent costs incurred as a result of transmission service
  - ▸ reflect the actual power flows of the transmission service
  - ▸ reflect the distance- and location-sensitive costs of the transmission service
  - ▸ reflect the prevailing direction of the flow, distinguishing between "with the flow" and "counter flow"
- Address any transition problems arising from the reform
  - ▸ Balance equity considerations associated with any reform with the potential efficiency improvements
  - ▸ Mitigate the hardships arising from any reform
- Allow customers an option to have stable prices over time

7/ *See*, Notice of Request for Public Comments on Regional Transmission Group Proposal, Docket No. RM93-3-000, November 1992.

- Be simple to implement and to administer.

QUESTION 1. Comment on these proposed criteria for assessing transmission pricing reform.

Staff recognizes that trade-offs between these objectives are unavoidable. It may not be possible to achieve efficiency, precision and administrative simplicity simultaneously. For example, the Commission will need to assess how complicated the administration of new transmission pricing policies might become in meeting these various criteria. The administrative costs may be higher for some criteria than others. In addition, the economic disruptions accompanying any departure from the status quo must be mitigated, if possible. Any remaining equity concerns then would be weighed against possible efficiencies. Reform is not sought for its own sake, but only as appropriate to support in an equitable manner the industry's evolution towards greater efficiency through competitive power markets.

III. REVISIONS TO THE CURRENT PRICING POLICY

In this section, commenters are invited to suggest changes to the Commission's current transmission pricing model. In Sections IV and V, we suggest possible alternative pricing models.

A. Incentives to Provide Service

As discussed above, some parties believe that the Commission's current implementation of its "or" policy does not provide sufficient incentives for transmission owners to provide service. 8/ They argue that if third parties pay only for the incremental cost of expansion (when this is higher than embedded cost), native load customers will receive no benefit. Those who support the "and" option contend that additional incentives are needed. For example, if third parties were required to pay embedded costs in addition to incremental costs, native load rates would decrease, thereby simultaneously providing a native load benefit and an expansion benefit.

QUESTION 2. Comment on whether the Commission's current "or" pricing policy provides appropriate and sufficient incentives to transmission owners and transmission customers. Explain when benefits to native load customers above those that would be obtained under the "or" policy would be appropriate and when they would not. Further, explain how the Commission could distinguish between appropriate and inappropriate native load benefits in the context of postage stamp ratemaking in which a utility's grid is viewed as an integrated single system. Should the possibility of an

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8/ The incentive for the transmission owner to provide service can be distinguished from the incentive to promote good decision making on the part of transmission customers. The latter incentive is discussed *infra*.

additional financial incentive depend, in part, upon whether the transmission service is offered voluntarily or is mandated? How could the Commission monitor and ensure that "incentives" are not a mechanism for recovering monopoly profits?

The Commission's pricing policy is designed, in part, to hold native load customers harmless. Implicit in that objective is that transmission rates compensate the transmitting utility for all costs incurred in providing the service.

QUESTION 3. Does the Commission's current pricing policy compensate the transmitter for all incurred costs? If not, what elements or cost factors are missing?

As previously discussed, a basic difficulty appears to be that unbundling transmission service will separate its pricing from the benefit sharing associated with power trades. With the exception of a few shared-savings transmission rates, transmission providers receive a cost-based price while power buyers and sellers receive possibly larger trade benefits. This is likely to be the case whether or not the Commission decides to reform its postage stamp ratemaking.

QUESTION 4. How does the unbundling of transmission service affect incentives?

Revenues from transmission service are frequently credited, one way or another, to native load customers by state regulators and the FERC. As a result, if the Commission were to allow higher prices for transmission services, most of the additional revenues would flow through to customers rather than shareholders of the transmitting utility.

QUESTION 5. What incentive to provide service remains if native load receives the benefit of incentives to provide transmission service and shareholders do not? Does the time lag in native load crediting affect this and, if so, how? Should the Commission consider revenue crediting less than 100 percent of third-party transmission revenues in developing rates for wholesale requirements service? How effective would this be given the fact that most "native load" rates are established at the state level?

The Commission has also accepted the concept of opportunity cost pricing, which Staff expects will be developed further in individual cases where specific fact patterns will be important in informing the Commission.

QUESTION 6. Does the Commission's opportunity cost pricing policy as articulated in *NU* and *Penelec* provide adequate incentives to the provider of the wheeling service?

QUESTION 7. Should the provision of third-party wheeling service be entitled to a different rate of return--higher or lower--to reflect the risks inherent in such transactions?

B. Incremental Pricing: Contract Vs. Average Incremental Costs

The Commission currently allows incremental cost pricing for grid expansion needed to fulfill a third-party transmission request. There appear to be two general ways to implement incremental cost pricing. One is to charge separate incremental prices in each transmission contract (contract pricing). The other is to charge a uniform price in all transmission contracts based on an average of current incremental costs (average incremental cost pricing). The Commission has begun to implement the first approach in its current pricing policy, although the full implications of that approach have not yet been raised in a case.

Under the contract pricing approach, a transmission customer pays for particular assets--those system upgrades associated with the customer's service. In exchange for paying for specific investments, the customer presumably would receive certain capacity rights. These rights would be specified in the customer's contract. Contract pricing would allow a transmission owner to enter into a contract, fixed as to capital recovery and with less risk for other costs, that gives customers substantial price certainty over the term of the contract. This can be especially important for non-traditional power producers that need project financing and may have little room to tolerate fluctuations in future transmission prices. The contract itself might contain provisions for renewal at the end of the contract term depending on the customer's needs and the utility's plans. In addition, the contract might fix certain pricing components, use inflation adjustments for some components, and allow others to be redetermined according to traditional regulatory procedures. The customer could not expect to have rights outside the contract, however. 9/

> QUESTION 8. Under contract pricing, would it be appropriate to develop a separate rate base for each customer? Or should native-load ratepayers remain responsible for a single ratebase with appropriate revenue crediting of all third-party wheeling revenues?

Under the average incremental pricing approach, all customers could be charged some average of the current incremental cost of the grid. This might involve replacement cost pricing or estimates of future expansion costs appropriately averaged over the next few years or some other approach. In contrast to the contract pricing approach, average incremental cost pricing applied uniformly could increase (or decrease) the rates of some third parties because of an expansion caused by others. In addition, some mechanism would have to be developed to ensure that all transmission costs are recovered since this form of incremental cost pricing may not necessarily cover the revenue requirement. Also, the issue of how such

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9/ Under this theory, native-load customers could be considered to have an open-ended, implicit contract with the transmission owner that does not terminate and in which all pricing components are redetermined periodically.

pricing for third-party transmission customers should compare to that for native load customers would have to be addressed.

QUESTION 9. What pricing approaches or rate design policies are needed to ensure an opportunity for recovery of total revenue requirements?

Several comparisons can be drawn between the two approaches, as a general matter. For example, under contract pricing, a customer would not pay for his vintage of incremental cost if the resulting service is not worthwhile to him. This provides a private check using the customer's own perception of value on whether an expensive upgrade is worthwhile. Average incremental cost pricing, by comparison, runs the risk that an expensive upgrade which incremental users would not be willing to finance will be built anyway because its costs are averaged into all third-party rates. In this case, the risk is checked by traditional regulatory oversight. Consequently, over-building risk is dealt with differently under the two approaches.

QUESTION 10. Is there a risk of over-building associated with average incremental cost pricing and, if so, how should such risk be handled?

Average incremental cost pricing for all customers is usually supported by noting that all customers are equally at the margin on any grid. That is, the system needs expansion for one customer only in the context of the aggregate demand of all customers. If any one customer were to reduce its demand, this could accommodate a demand expansion on the part of any other customer, assuming the same facilities would be used by both. Consequently, some would argue, all customers need to face the same incremental price signal at the same time for any particular point on the grid.

Price signaling is different under contract pricing. At any given time, the same price signal is given to all customers that cause expansion, but not otherwise. This succeeds in signaling customers about the financial consequences of future increases in their usage. With respect to decreases in usage, the customer is given a correct price signal to the extent that resale markets work well. That is, if transmission customers can resell existing capacity rights, current customers will be able to reduce their usage. The two approaches, then, depend on different mechanisms to transmit price signals--one uses regulated prices solely, while the other relies on regulation combined with an active resale market.

QUESTION 11. Is it important that all customers face the same incremental price signal and how effective will each approach to pricing be in achieving a single incremental price?

Uniform implementation of incremental cost pricing treats old and new customers the same, *i.e.*, in a non-discriminatory manner, and typically does not require establishing cost

responsibility on a customer-by-customer basis. 10/ In contrast, old and new customers will pay different prices under contract pricing. Whether this difference is due or undue discrimination is a separate question.

> **QUESTION 12.** Would the fact that old and new customers might pay different prices under a contract pricing regime constitute undue price discrimination?

Incremental cost pricing charged uniformly for all customers has the advantage that it would be simpler to administer. Contract pricing requires keeping track of investment vintages and associating these with particular customers. The accounting would become increasingly complex over time.

> **QUESTION 13.** Please comment on whether contract pricing is appropriate for wholesale transmission service and whether it can be administered over the long term at reasonable cost. Are the administrative costs large when compared to the risk of poor investment decisions? Would such pricing give good overall price signals with so many different prices for similar services? In competitive markets, reselling works to eliminate such price differentials. Would reselling be effective in creating a single transmission price signal, say between a specific pair of points on the grid? Is there likely to be a significant resale market for anything other than major corridor service?

> **QUESTION 14.** Should the Commission allow a different rate of return on transmission investment to reflect different riskiness depending on whether a contract pricing or average incremental cost pricing approach is adopted? If so, how would the different riskiness be assessed?

C. Other Issues Relevant to the Current Pricing Policy

Pricing for Grid Expansions. Although the Commission has accepted the concept of incremental cost pricing for transmission service requiring a grid upgrade, it has not specified any particular method for calculating such costs. A method will have to be identified when a utility proposes incremental cost pricing in a specific case.

> **QUESTION 15.** What is the appropriate way to price transmission services that require grid upgrades? Is the approach of computing the revenue requirement with and without the third-party transaction an appropriate incremental pricing approach

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10/ The British National Grid Company charges the same, non-vintaged prices to all users located within the same geographic zones. The Company concluded that it could not fulfill its legal obligation to provide non-discriminatory service if it charged different prices to different users at similar locations with similar characteristics. *See* National Grid Company, *Transmission Use of System Charges Review, Investment Cost Related Pricing--Response to Comments*, Coventry, England, October 30, 1992.

for grid expansion? What would be a reasonable time period to forecast costs and loads for such calculations?

Calculation of Line Losses. A transmission customer may pay for transmission losses either through an in-kind payment (replacement of the energy losses) or as part of the basic transmission rate. The payment typically is based on average line losses, as opposed to marginal line losses which would be higher in most cases. 11/

QUESTION 16. Is the current practice appropriate and, if not, what changes should be made?

Direction of Power Flows. Some transmission transactions may have beneficial effects on transmission systems, *i.e.*, relieve constraints, if they involve new power flows that would go against the prevailing flow.

QUESTION 17. Should transmission pricing take account of the direction of power flows? If so, should a customer be entitled to some form of credit if a particular transaction helps to alleviate a constraint?

Network Service vs. Point-to-Point Service. Commenters are invited to discuss pricing issues pertaining to either point-to-point service or more flexible services such as so-called network service. While there is no universally accepted definition of network service, Staff understands the term to mean transmission service that allows the user to vary its schedule and points of delivery and receipt on the grid without paying an additional charge for each change.

QUESTION 18. Is staff's definition of network service reasonable? Provide recommendations on how network service should be priced.

Ancillary Transmission Services. Commenters are invited to address the pricing of ancillary services, such as voltage support or reactive power service, load following services, scheduling and dispatch service, and operating reserves. Such services are automatically provided as part of bundled power service, such as requirements service or retail service. As more unbundled transmission service is provided, such services can be expected to become increasingly important. Staff recognizes that an important issue for the Commission to deal with is whether the Commission can order the provision of ancillary services and, if so, which ones. This inquiry will focus on the pricing issues and defer the provision question for later consideration.

11/ *See* Northern States Power, 59 FERC ¶ 61,100 (1992), for a discussion of the Commission's current policy on the use of average and marginal line losses in ratemaking.

QUESTION 19. Can commenters suggest other ancillary services, in addition to those listed above? Provide recommendations on how such ancillary services should be priced.

IV. REFORM OF THE CURRENT PRICING POLICY: FIRM SERVICE PRICING ISSUES

It is possible to reform various dimensions of the current model. For example, postage stamp ratemaking could be replaced with distance sensitive pricing. Likewise, the contract path model could be changed to account for parallel flows. Importantly, reform of these dimensions could be combined in various ways. For instance, a postage stamp, parallel path approach is at least theoretically possible. Staff has no preconceived model of pricing. Commenters are invited to suggest any alternatives they believe are appropriate. The following discussion is intended to illustrate the kinds of issues and trade-offs that the Commission is likely to face in evaluating such models.

A. Distance-Sensitive versus Postage Stamp Rates

A postage stamp rate entitles a user to transmit power over any portion of a utility's grid, whether for 10 or 200 miles, for the same rate. Under postage stamps rates, the cost of providing short-distance transmission or transfer service is implicitly averaged with that of long-distance transfer service. This may create a bias in favor of long transfers and against shorter ones.

QUESTION 20. Does the failure of postage-stamp rates to recognize distance create important cross subsidies between long-distance and short-distance transfers?

Several alternatives to postage stamp rates exist that would make the price paid sensitive to the distance involved. One form of distance-related pricing is the MW-mile method, which could be implemented in numerous ways. It could be used to price power flow within a single utility (as in the case of some New Jersey utilities) or among several utilities, as in the ERCOT experience in Texas. 12/

Another way to incorporate distance into transmission rates would be to develop rate zones within a single utility's grid. This might involve dividing the grid into parts for ratemaking purposes. Power moving across each zone would be identified in load flow analyses, which would help to sort out whether the zones and utilities have a parallel relationship (where only a portion of the total power flow burden is physically carried by a particular utility or zone) or a serial relationship (where *all* of the power flow burden is

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12/ An example of the MW-mile method has been proposed by Alfred F. Mistr, Jr. and Everard Munsey, "It's Time for Fundamental Reform of Transmission Pricing," *Public Utility Fortnightly*, July 1, 1992, pp. 13-16.

carried by each of the utilities or zones). Some observers have even suggested facility-by-facility pricing, which would charge users a load-ratio price for each facility used. In the extreme, each facility, *e.g.*, a line or a substation, would effectively become its own rate zone. Further, the concepts of zones and MW-miles could be combined in principle. That is, MW-miles could be used to allocate costs within zones.

> QUESTION 21. How much do transmission costs vary with distance and can such costs be easily quantified? Comment on distance-sensitive pricing in general and on MW-mile methods and zonal methods in particular. Comment on the importance of distance-related rates in providing correct incentives. Would distance-sensitive pricing proposals apply to point-to-point service, or network service, or both?

In addition to incorporating distance correctly, it is also important that transmission prices promote good decisions regarding where to locate new generation facilities. The long-term expected congestion at certain critical grid locations may not be adequately incorporated into distance-sensitive prices. Prices may have to be sensitive to location as well.

> QUESTION 22. Do postage-stamp or distance-sensitive rates provide adequate price signals about the location of new generators? If not, how can transmission prices help promote good location decisions?

B. Contract Path versus Parallel Path Pricing

As discussed in Section I, the contract path approach currently used by the industry may no longer fit its planning and operating needs. Some utilities whose transmission facilities actually carry the power, but who are not part of the contract path, are not likely to be adequately compensated under the contract path approach. This mismatch between compensation and actual flows was widely accepted in the past because of the industry's belief that the overall costs and benefits were roughly balanced and sometimes an explicit effort was made to achieve a balance by sharing the cost of new facilities or by taking turns in building. However, it is staff's impression that the mismatch is growing in magnitude and *ad hoc* efforts to achieve a balancing of costs will no longer work.

Contract path pricing may also create inefficient incentives. For example, it may dilute the incentive of transmission owners to build new transmission assets since others may be able to use the new facilities without charge. Contract path pricing could also complicate coordinated building activity among transmission owners. Regional grid upgrades may need to be made sequentially by several utilities over several years. The utility that first upgrades runs the risk that other utilities may not be able to complete the promised investments that would have provided the expected reciprocal benefits. The other utilities would then get to use the first utility's new capacity for free. No one would want to build first if such a risk were large.

Alternatively, contract path pricing may create an incentive for a utility without significant transmission facilities to build an inefficiently small (low voltage) line in the midst of a high voltage grid in order to create a contract path, assuming that it could meet appropriate reliability criteria. Even with the new line, the utility's power will still flow over the higher voltage lines if, as is likely, there is less resistance on those lines. The result would be that an inefficient investment would be made in order to gain access to a neighboring high voltage grid for free. Such a strategy can benefit the utility if the expected savings in procuring power exceed the investment cost of the needed (token) transmission facilities. In contrast, the more appropriate calculation would examine whether such a low voltage line has any place in the regional transmission plan. Such a line, for example, may make an ineffective contribution to regional reliability or perhaps even detract from reliability if it cannot withstand first contingency power surges when elements of the neighboring high voltage grid fail. 13/

If the industry changes its contract path contracting approach, corresponding pricing changes would be needed. An alternative to contract path ratemaking would be some form of parallel path pricing. Parallel path pricing would compensate transmission owners for use of their grids based on the fraction of the total flow carried by each owner. The fraction of flow carried would be determined by an engineering analysis of the load flow. Each transmission owner's price would recover a contribution to capital.

Another alternative would be to establish capacity rights to the *regional* grid, either on a point-to-point or network-wide basis. Such rights are not systematically defined under the current contract path approach, although the utilities in the Western Systems Coordinating Council have begun to address this issue in their process for rating the simultaneous incremental transfer capability of grid additions. 14/ Payment for the capacity right would constitute the capital contribution under this approach.

QUESTION 23. Assess the benefits and problems of specific alternatives to the contract path approach and the need for such alternatives.

13/ A grid that is built to withstand so-called "first contingencies" is one that can continue to operate within the established safety criteria after it has lost the services of the single, largest and most critical element in the grid, perhaps a critical transmission line or a large generator.

14/ The WSCC process tries to produce line ratings which recognize that individual transmission lines are embedded within a larger network. The rating of any line depends on the operation and configuration of the larger network. Once a line's capacity rating is established through an open "peer review" process, the rating sets limits on the amount of power that can be transmitted over the line.

Parallel path pricing or some other mechanism such as the establishment of capacity rights might neutralize the incentive for transmission owners to not build when they should, and for non-owners to build inefficient facilities. The poor incentives of contract path pricing, however, might be replaced by other poor incentives under parallel path pricing. For instance, parallel path pricing might create an incentive for a utility to build lines at voltage levels much higher than those of its neighbors in order to attract large amounts of parallel flow from neighboring utilities and thus be compensated for them.

> QUESTION 24. Does the current approach to contract-path pricing provide appropriate incentives for transmission construction? Would some other approach, parallel path pricing or better defined capacity rights, provide better incentives for such construction?

This phenomenon apparently exists now even in the absence of parallel flow pricing. Some neighboring utilities trade amounts of power that are smaller than the rating of their direct interconnections and yet a substantial fraction of the flow is carried on higher voltage neighboring systems. These utilities are understandably concerned that parallel path pricing could cause them to pay a third party for transmission service even though their jointly owned interconnection could carry their trade in the absence of the neighbor's lines. This situation needs to be considered in any reform involving parallel path pricing.

> QUESTION 25. Comment on how the Commission should address situations where utilities are required to pay third parties even though their interconnection would appear to be adequate.

One way might be to exempt directly interconnected neighbors from parallel path pricing. As mentioned, another solution might be to establish firm transfer rights that entitle a holder to use the system at no additional charge (except for line loss payments) up to the amount of the firm rights. Usage in excess of the rights could be subject to parallel path pricing. The rights could be established in advance according to ownership shares, demand charge payments, or other financial considerations.

> QUESTION 26. If you would propose to establish capacity rights, comment on the consequences of such exemptions on your proposal.

In questioning the incentives under both pricing regimes--contract and parallel flow--Staff understands that good decisions are frequently made. The industry norm is that high voltage lines do get built now and inappropriate low voltage lines, while possible, are seldom built. Nonetheless, we believe that a pricing regime based on good incentives will improve performance.

> QUESTION 27. Comment on the relative effects of contract path and parallel pricing on the incentives for cost-effective construction of transmission facilities.

Staff believes that parallel path pricing could improve decision making about the use and expansion of the grid. It can more accurately match usage with cost causation by identifying where the power is flowing. In so doing, the parallel portions and serial portions of the flow can be identified. Transmission assets arrayed in a parallel position to carry the power of a particular transaction will share the burden of the flow and accordingly could be allocated an appropriate fraction of the price. Assets arrayed in a serial position will each carry the same power burden and accordingly their costs could be appropriately added. Parallel path pricing could produce dramatic changes from contract path rates. This not only could help to sort out how the power flow burden is shared among parallel path owners, but also could clarify how much of a burden is imposed on serial path owners.

Parallel path pricing would require power flow studies to identify which parallel paths are used in particular transactions. Incorporating load flow information in its pricing practices would be a clear departure for the Commission. The Commission's recent Notice of Proposed Rulemaking on transmission information in Docket RM93-10-000 is relevant here. Staff expects that the information needed to conduct power flow analyses would be assured as a result of this proceeding. Power flow studies would complicate ratemaking considerably. Such a complication may be largely unavoidable, however, since it appears that most proposed pricing reforms would involve such analyses.

QUESTION 28. Provide suggestions for reforms that would not require power flow studies, as well as suggestions for procedures to resolve technical disputes about such studies.

Staff sees important comparisons between contract pricing of capacity rights, discussed in the previous section, and parallel path pricing. For instance, payment for the capacity rights associated with contract pricing, perhaps through a reservation charge, would be the means for recovering capital costs. Most proposals to create capacity rights have small usage charges that recover only variable costs, such as line losses. In contrast, parallel path pricing recovers a capital cost contribution in rates for usage, not reserved capacity.

QUESTION 29. Can these two concepts be combined or are they mutually exclusive?

In addition, trading (reselling) is contemplated in most capacity rights proposals. If two parties both own capacity rights between points A and B on the grid, they presumably could compete to resell those rights to a third party. This would be a version of contract path competition. Such competition would appear to be ruled out in a parallel path pricing model since all the utilities on the parallel path would jointly determine which portion of a transaction is carried on each utility's system. Presumably, no utility would charge for or compete to provide service determined to be carried on someone else's system. The utilities on the parallel path are those that jointly possess parallel capacity rights, in effect. Consequently, reselling in a capacity rights model could involve competition among parallel

rights holders to provide service between points of receipt and delivery, while reselling in the parallel path model only would involve returning the capacity to the joint service providers with no competition among them.

QUESTION 30. Is this an important difference between the two models and, if so, which is more appropriate?

C. Equity and Fairness Considerations

The current pricing policy, based on the postage stamp, contract path approach, has prevailed for many years and provides the basis for most trade today. Any change is likely to be disruptive and to affect participants in different ways. Dealing with the equity and fairness ramifications of any pricing reform is important.

QUESTION 31. Comment not only on the efficiency consequences of possible reform, but also on its fairness and equity implications. Provide specific suggestions on how the Commission would manage any transition to a new pricing system, how it would mitigate hardships associated with the transition and how any change would be coordinated among all affected utilities.

QUESTION 32. A possible approach to mitigation would be to apply pricing reform prospectively only, *i.e.*, for new transactions, but not existing ones. If the Commission believed that some version of parallel pricing was appropriate, for example, how should the need for mitigation be weighed against the need to coordinate parallel path pricing among all affected transmitting utilities?

V. REFORM OF THE CURRENT PRICING POLICY: NON-FIRM SERVICE PRICING ISSUES

A. Capital Recovery in Non-Firm Transmission Rates

Non-firm transmission service can be interrupted by the transmitting utility more easily than firm transmission service. A fundamental issue of non-firm transmission pricing is how much of a contribution to fixed costs is appropriate and, further, whether any "demand charge" is appropriate. Such a charge is common practice in the industry today. Despite current practice, many observers believe that recovery of capital costs in non-firm wheeling rates can interfere with short-term efficiency. They argue that the Commission's acceptance of non-firm rates with a capital cost adder discourages economy transactions that could lower generation production costs.

The short-run marginal costs (or variable costs) of transmission consist only of line losses and so-called congestion costs. Congestion costs are the short-term opportunity costs of using constrained facilities, such as the cost of redispatching generation units in order to

free up transmission capacity. 15/ Congestion costs could be addressed by using spot pricing, as discussed *infra*. From this perspective, many economists conclude that non-firm service prices should recover only variable costs. The reasoning is that users of non-firm service should not pay for capacity costs, *per se*, since capacity is not built for them--their service can always be interrupted when the capacity becomes tight.

The Mid-Continent Area Power Pool (MAPP) has used a variant of short-run marginal cost pricing to pay for the transmission service that allows for short-term coordination transactions within the pool for years. Critics of this pricing system argue that non-firm transmission users are "free riders" if the grid has adequate capacity. That is, if grid capacity is unconstrained, congestion costs are zero and non-firm users pay only for line losses. Transmission users can avoid making any contribution to capital by subscribing only to non-firm service. Under current rate base treatment, a utility's native load would not be compensated by such users.

In practice, this problem can be and sometimes is addressed by a requirement that all users make some contribution to capital, perhaps through ownership requirements or capacity deficiency payments or some other contribution mechanism. This approach has been adopted by MAPP, for example. In effect, the transmission owners develop rules that ensure that all users pay a fair share of the capital costs and then pay only for line losses on a transaction-by-transaction basis.

Under one theory, another answer to this dilemma is not to install excess capacity. If capacity is optimal, in this view, it would be occasionally short and so non-firm users would have to pay substantial congestion costs in order to avoid interruption during peak loading periods. Many would then desire firm service. These new firm service users would make capital contributions that adequately compensate native load. In effect, the free rider problem would disappear if firm and non-firm service could be made equally attractive by proper adjustment of capacity, according to this theory.

It is not clear, however, that the optimal level of capacity is one that necessarily makes firm and non-firm service equally attractive over the long run. There are several reasons to believe that some reasonable amount of excess transmission capacity might be optimal. Lumpy investment combined with uneven demand expansion can create long periods of "excess capacity" even if capacity planning is optimal. Some have also argued that, given the relative importance of generation in comparison to transmission, some excess transmission capacity above that needed for reliability purposes should be tolerated in order

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15/ Congestion charges can be viewed as contributions to capital. *See* William W. Hogan, "Electric Transmission: A New Model for Old Principles," *Electricity Journal*, March, 1993.

to have the infrastructure needed to facilitate a competitive generation sector. 16/ In addition, excess transmission capacity would be needed in theory in the absence of very short-term pricing mechanisms that signal the need for end users to curtail during peak transmission loading episodes. The excess in such circumstances would be required to handle short-term needs that cannot be rationed by price. If utilities install excess transmission capacity, for one of these or any other good reason, it could be freely exploited by non-firm users if they paid no capital-contribution charge.

QUESTION 33. Comment on this dilemma: how to give good short-term price signals through non-firm transmission pricing, while avoiding the possibility that non-firm users would make no contribution to capital costs. Is the dilemma important in practice?

B. Spot Pricing for Non-Firm Transmission

Spot transmission pricing refers to very short-term pricing that would reflect hour-to-hour conditions on the grid. Spot prices consist of marginal line losses plus congestion charges. 17/ A spot transmission rate has no demand charge and makes no contribution to capital, except through the highly volatile congestion charge. Such a concept clearly has no place in the Commission's regulation unless the Commission first makes the threshold determination that non-firm demand charges are inappropriate, as discussed above. If the Commission reaches such a determination, Staff is interested in understanding how to implement spot pricing and whether it would improve efficient operation. Note that the issue of how to recover capital costs could be addressed separately, in which case the issues raised in the previous section are relevant.

The theory of spot pricing for transmission is closely related to spot power markets. In the existing literature, *e.g.*, *infra* note 17, well functioning spot markets for power are assumed to exist at multiple locations (buses) around the grid. 18/ These would be multi-lateral trading institutions, perhaps organized like a stock exchange or commodities market. The theory of spot transmission pricing is usually based on the assumption that these

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16/ Charles G. Stalon, "Pricing Transmission Network Services," Presentation to American Bar Association, Denver, Colorado, February 1993, at 8. Generation costs typically constitute about 60 to 75 percent of the price that final customers pay for electricity. Therefore, it is argued that some overinvestment in transmission is desirable if it produces a competitive generation market that lowers generation costs.

17/ For an introductory discussion of spot pricing, *see* K. Kelly, J.S. Henderson, and P. Nagler, *Some Economic Principles for Pricing Wheeled Power*, National Regulatory Research Institute (Columbus, Ohio, August 1987).

18/ A bus is a point on the grid where power is either injected by a generator or taken off by a customer's load. Buses are connected by transmission lines.

dispersed spot markets for power are workably competitive. The literature does not address the question of how well spot transmission pricing would perform if the corresponding spot power markets are not competitive. Regardless, such spot markets for power do not exist today and would represent a substantial departure from the quite active bilateral arrangements for trading power today. Some of the benefits of spot transmission pricing may not be achievable without reform of the institutions for trading short-term power. Accordingly, spot transmission pricing might require more than reform of the Commission's regulation of transmission pricing. The needed institutional reform may be more ambitious than the other pricing reforms discussed in this paper.

> QUESTION 34. Comment on the observation that spot transmission pricing might require more than reform of the Commission's regulation of transmission pricing and might involve reform of the underlying market institutions for trading power.

Spot pricing proposals have been developed by several analysts. 19/ Staff is interested in understanding how such pricing could be implemented by the industry to improve coordinated operations.

> QUESTION 35. Would spot pricing be intended to improve *ex ante* price signals or be the basis of an *ex post* financial settlements system?

> QUESTION 36. Is there a need for spot pricing of inadvertent, unscheduled power flows and, if so, how would this interact with the spot pricing of scheduled transfers?

19/ *See* F.C. Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Norwell MA: Kluwer Academic Publishers, 1988); W.W. Hogan, "Contract Networks for Electric Power Transmission," Working Paper E-90-17, John F. Kennedy School of Government, Harvard University, Cambridge MA, September 1990; M.L. Baughman, S. Siddiqi and J. Zarnikau, "Advanced Pricing in Electrical Systems," University of Texas Working Paper, October 1992; and, M.B. Lively, "Tie-riding Freeloaders--The True Impediment to Transmission Access," *Public Utilities Fortnightly*, December 21, 1989.

UNITED STATES OF AMERICA 64 FERC 61,278
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Elizabeth Anne Moler, Chair;
Vicky A. Bailey, James J. Hoecker,
William L. Massey, and Donald F. Santa, Jr.

Interregional Transmission Coordination Forum	)	Docket No. ER92-667-000

ORDER ACCEPTING FILING AND
DENYING REGIONAL TRANSMISSION GROUP STATUS

(Issued September 3, 1993)

The Commission in this docket is accepting for filing organizational materials of a voluntary transmission coordination group, the Interregional TransmissionCoordination Forum (ITCF), including an agreement by members of the group to attempt to resolve " ... disputes arising from the operation and use of the interconnected transmission systems ..." through a non-binding dispute mediation process. 1/ This coordination group does not constitute a regional transmission group (RTG) as discussed in our recent policy statement concerning RTGs, 2/ and the materials filed do not constitute an RTG Agreement as described in the policy statement. The materials filed do not present a sufficient basis for us to consider at this time giving any special deference to: decisions or proposals by ITCF that would affect jurisdictional rates and services under the Federal Power Act; rates and charges contained in agreements entered into by ITCF members; or, other outcomes arising from ITCF processes. Nor do the materials provide a sufficient basis for us to find that ITCF is or is not in the public interest. However, because the materials have been voluntarily filed and contain agreements and practices that arguably may affect jurisdictional rates and services, and because they do not contain any elements that appear unjust, unreasonable, or unduly discriminatory or preferential, we will accept them for filing.

As discussed below, while this coordination group clearly is not an RTG, we encourage the members to work toward developing RTGs as described in the recent policy statement.

I. Introduction

On July 6, 1993, the Interregional Transmission Coordination Forum (ITCF) filed certain organizational materials and asked that the Commission "affirmatively recognize ITCF as a

1/ ITCF filing; Dispute resolution procedure at 1.2.

2/ Policy Statement Regarding RTGs, 64 FERC 61,138

functioning voluntary regional transmission association . . . functioning in the public interest." 3/ The ITCF states that the filing is made under section 35.12 ofthe Commission's regulations 4/ as a "contract and practices affecting rates (that is, as a "rate schedule" of the public utility members . . . .)" 5/ It asks the Commission to authorize the Administrator of ITCF to make future filings on behalf of the members of ITCF. The ITCF asks the Commission to allow ITCF members to resign without Commission review. Finally, the ITCF also requests an effective date of 60 days after the filing. 6/

Notice of the filing was published in the Federal Register, 7/ with comments due on or before July 20, 1993. Timely motions to intervene were filed by Alabama Electric Cooperative, Inc. (AEC), Old Dominion Electric Cooperative (ODEC), Public Service Electric and Gas Company (Public Service), North Carolina Electric Membership Corporation (NCEMC), Cajun Electric Power Cooperative, Inc. (Cajun), 8/ and Louisiana Energy and Power Authority (LEPA). In addition, the Maryland Public Service Commission (Maryland PSC) filed a notice of intervention. An untimely motion to intervene was filed by the Public Utilities Commission of Ohio (Ohio). No arguments are raised by Maryland PSC, ODEC, PSEG, NCEMC, or LEPA. Ohio requests a technical conference. Cajun and AEC argue that the ITCF materials are not subject to the Commission's jurisdiction under section 205 of the Federal Power Act (FPA) and should therefore be rejected. Cajun also objects to various provisions in the Charter and Bylaws. Cajun's and AEC's arguments will be discussed below.

3/ ITCF filing; Cover letter at 3. ITCF filed similar materials in Docket No. ER92-667-000 on June 26, 1992. The Commission has not acted on that filing. ITCF requests that the Commission deem the original filing to be superseded by the July 6, 1993 filing.

4/ 18 C.F.R. 35.12 (1993).

5/ ITCF filing; Cover letter at 3.

6/ ITCF filing; Cover letter at 2, 4.

7/ 58 Fed. Reg. 38,564 (July 12, 1993).

8/ Cajun's motion was actually styled as a supplement to its earlier motion to intervene filed in response to ITCF's first filing, dated July 14, 1992. For convenience, we will refer to Cajun's July 14, 1992 filing in this order, since the supplement incorporates by reference the arguments made in the July 14, 1992 filing.

II. Background

ITCF explains that it is "an open-membership regional organization devoted to the voluntary resolution of issues confronting those engaged in the transmission of bulk power in the eastern United States." Its mission is to

> [p]rovide a forum to promote cooperation and coordination between the owners, operators and users of interconnected transmission systems so as to assure system integrity and maximum reasonable use of facilities for economic benefit and to encourage investment in additional facilities to maintain reliability or enhance transfer capability or both.

ITCF notes that it had first filed certain organizational materials on June 26, 1992, including the Charter, Bylaws, and dispute resolution procedure. The new filing also includes a current membership list and a slightly revised dispute resolution procedure. The filing states that the Bylaws are now "fully implement[ed]." 9/

In addition to setting forth the ITCF's mission, the Charter lists certain principles to which members "obligate" themselves. 10/ The principles are as follows:

1. Development of new power transfer arrangements must observe:

   h reliability criteria including those set forth in the NERC Operating Guides;

   and

   h the rights of the owners and other users of the facilities affected by the transfer.

2. New power transfer transactions should not commence without first affording the likely affected parties among the other subscribers hereto a reasonable opportunity for review and comment.

9/ ITCF filing; Cover letter at 1-2.

10/ ITCF filing; Cover letter at 3.

3. Appropriate standards should be developed cooperatively and, if appropriate, adopted by agreement which:

   - h provide for the reliable, efficient, and equitable utilization of transmission facilities; and
   - h foster the planning and completion of additional facilities.

The Charter also sets forth the function of the ITCF, which is to establish a "forum through which the stated mission can be pursued on a completely voluntary basis consistent with the stated principles." 11/

The Charter states that the ITCF forum will:

1. Meet periodically to exchange information and establish ad hoc study groups as necessary to facilitate resolution of broad issues;

2. At the request of participants, establish ad hoc voluntary dispute resolution groups to mediate differences in specific cases and to pursue this approach before alternatives;

3. Promote the development of procedures and technology needed to support interconnected operations; and

4. Extend every reasonable effort in pursuit of the foregoing. 12/

The ITCF Bylaws provide for meetings of the ITCF and set forth the rules of notice and participation. They set forth rules governing voting and provide for the creation of various committees (including a Planning Committee and a Dispute Resolution Committee). There are also provisions concerning matters such as officers, use of checks, and amendments.

11/ ITCF filing; Charter at 1.

12/ ITCF filing; Charter at 2.

Finally, the filing includes a Dispute Resolution Procedure, which applies to disputes between members and non-members as well as to disputes among members concerning interconnected transmission systems. 13/ The procedure is to be voluntary and non-binding. The members agree to make a good faith effort to resolve disputes through this procedure. The dispute resolution procedure calls for a mediation panel and provides various standards and procedures related to such a panel. The mediation panel cannot render a decision; instead, it will try to bridge the differences between the opposing sides. There are various procedures and requirements to govern the meetings among the disputants and the mediation panel, as well as provisions concerning costs, time limits, notice, and withdrawal. The parties may by mutual agreement change these procedures. 14/

III. Discussion

Under Rule 214 of the Commission's Rules of Practice and Procedure, 15/ the notice of intervention and timely, unopposed motions to intervene serve to make all those who made such filings parties to this proceeding. We find that there is good cause to grant Ohio untimely intervention, given the interests of the constituency that it represents and the apparent absence of any undue prejudice or delay.

Cajun and AEC argue that we should reject the ITCF filing because the documents filed are not "contracts" or "practices" affecting rates and thus are not required to be filed under FPA section 205(c). 16/ They argue that the filing is an undefined course of conduct rather than a contract. According to AEC, ITCF wants the Commission to approve the filing in order to receive some degree of implicit antitrust immunity, even though it is impossible to analyze the future effect of the ITCF on competition.

AEC and Cajun have not shown that the Commission lacks jurisdiction to review the ITCF filing. The documents filed contain agreements and "practices" that may affect or relate to rates or services within the meaning of section 205(c). In particular, the members' agreement to make a good faith effort to resolve disputes arising from the operation and use of the interconnected transmission system, in accordance with specified

13/ ITCF filing; Dispute resolution procedure at 2.0.

14/ ITCF filing; Dispute Resolution Procedure.

15/ 18 C.F.R. 385.214 (1993).

16/ 16 U.S.C. 824d(c) (1988).

procedures, may affect transmission in interstate commerce. 17/ Furthermore, ITCF's mission statement demonstrates that ITCF intends to take substantive actions that may affect or relate to transmission in interstate commerce. Indeed, ITCF members presumably will vote at ITCF meetings on issues regarding coordination, planning, and reliability. While the Commission in its discretion may not necessarily require that agreements and practices providing for such fora must themselves be filed, this does not mean that the Commission is prohibited in a case-specific context from requiring such agreements to be filed, or in its discretion from accepting them as voluntary filings. 18/ In the absence of a specific rate or transmission-services case before us, the Commission ordinarily would not require the filing of documents such as the ones in this docket. However, since the ITCF documents have been voluntarily filed, and since they clearly may give rise to substantive decisions affecting the provision of transmission in interstate commerce, we will review them under the standards of section 205.

17/ The members of ITCF have obligated themselves to pursue voluntary dispute mediation procedures before coming to the Commission with their disputes. ITCF filing; Charter at 2. ITCF itself states that members undertake specific obligations, such as an obligation to meet periodically and to engage in good faith mediation. ITCF filing; Cover letter at 3.

18/ The Commission has flexibility and exercises discretion in deciding what must be filed. While we might not routinely require the filing of operational documents or certain types of provisions, on a case-specific basis we may require them to be filed. Prior Notice and Filing Requirements Under Part II of the FPA, 64 FERC 61,139 (1993); Town of Easton, Maryland v. Delmarva Power and Light Co., 24 FERC 61,251, 61,531 (1983) (recognizing that almost anything could be considered jurisdictional, and that Commission has discretion in deciding what must be filed; requiring filing of certain provisions affecting allocation of capacity); Northern California Power Agency, 38 FERC 61,195 (1987)(Commission would be inundated if section 205 were interpreted literally; focuses on material effect on rates or services); Central and South West Services, Inc., Opinion No. 332, 48 FERC 61,197, 61,733-4 (1989) (minute details of day-to-day operations need not be filed, but in this instance, planning reserve level must be specified in contract and filed, since change in reserve level may directly affect rates).

Cajun argues that if we accept the ITCF filing, we should make it clear that we will afford no deference to agreements reached pursuant to the efforts of the ITCF. 19/ We wish to assure Cajun that we will continue to review contracts thoroughly under the just and reasonable standard of FPA section 205. We have an overriding responsibilityto review contracts to protect the interests of ultimate consumers 20/ and to ensure that contracts are just and reasonable. 21/ Agreements filed by ITCF member public utilities under FPA section 205 will be given this same review. We will not afford ITCF decisions the special deference that we may be willing to give to decisions reached by an RTG.

Cajun also asks that if the Commission does accept the ITCF filing, the Commission "hold a hearing" on the filing. 22/ If Cajun means a trial-type evidentiary hearing before an administrative law judge, we do not agree that such a hearing is needed. It is well settled that an evidentiary hearing is required only when there are disputed issues of material fact that may not be resolved through an examination of written submissions. 23/ Cajun has made no attempt to demonstrate that there are even disputed issues of material fact, much less that such issues cannot be resolved based on the written submissions. Nor do we believe that a further paper hearing is needed.

19/ Cajun's July 14, 1992 motion to intervene at 11.

20/ FPC v. Interstate Natural Gas Co., 336 U.S. 577, 581 (1949); Atlantic Refining Co. v. Public Service Commission, 360 U.S. 378, 388 (1959); Maine Public Service Co. v. FERC, 579 F.2d 659, 664, 668 (1st Cir. 1978).

21/ Boston Edison Co. v. FERC, 856 F.2d 361, 373-374 (1st Cir. 1988); Arkla v. Hall, 453 U.S. 571, 581 (1981) (contracts do not affect supremacy of statute); Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1153 (D.C. Cir. 1984), cert. denied sub nom. Transwestern Pipeline Co. v. FERC, 476 U.S. 1114 (1986).

22/ Cajun's July 14, 1992 motion to intervene at 10.

23/ Environmental Action and Consumer Federation of America v. FERC, No. 91-1403, slip op. at 23 (D.C. Cir. July 2, 1993) (citing cases); Judith B. Moreau, et al. v. FERC, No. 91-1542, slip op. at 23-24 (D.C. Cir. Jan 15, 1993) (citing

Ohio asks that we convene a technical conference because the "broad and general" nature of the filing makes it impossible to analyze the consequences of Commission approval. We do not believe that such a conference is necessary. As discussed above, we are not committing ourselves to affording any special deference to agreements reached under the ITCF procedures. We will review any contracts to ensure that they meet the standards of FPA section 205. Moreover, any person aggrieved by ITCF processes or procedures may file a complaint with the Commission under FPA section 206.

Cajun argues that the ITCF's membership criteria may discriminate improperly among original participants, other transmission owners, and transmission users. 24/ Cajun points out that there are discrepancies among the Charter, the Bylaws, and ITCF's cover letter accompanying the original filing.

There are, in fact, some differences between the membership rules set forth in the Charter and Bylaws. The Bylaws are very broad, providing that "[a]ny owner, operator, or user which is not an ultimate consumer, of interconnected electric transmission systems . . . . who signs the ITCF agreement . . . is a member . . . ." 25/ The Charter, on the other hand, provides that "[t]he undersigned, being owners and operators . . ." subscribe to the Charter and that other owners and operators are encouraged to

> participate . . . and to become signatories to these principles. Others who are only users of transmission and who subscribe to the above stated principles are invited to participate in this Forum. 26/

This language is confusing, both in itself and in relation to the Bylaws. However, we do not read the language to create different classes of members with different rights. The membership list (attached) includes non-owners, and the Bylaws in no way suggest tha their status is less than that of owners or operators, or that the status of the original signatories is any higher than that of others. The ITCF cover letter describes the ITCF as an "open-membership" organization, 27/ and we will accept the filing based on this characterization. We interpret the provision as allowing, at a minimum, membership to any entity

24/ Cajun's July 14, 1992 motion to intervene at 11-12.

25/ ITCF filing; Bylaws, section 1.01.

26/ ITCF filing; Charter at 2.

27/ ITCF filing; Cover letter at 1.

that is subject to, or eligible to apply for, an order under section 211 of the FPA. 28/ Anyone who is denied membership in the future, or forced to accept a lesser status than other members, may file a complaint with this Commission.

Next, Cajun objects to the provision that ITCF's initial resources will be materials and services contributed "equitably" by members. 29/ Cajun argues that the provision is too vague to analyze. 30/ We find no grounds to reject the provision. However, if any member believes that the ITCF is violating the Bylaws by requiring inequitable contributions, it may file a complaint with the Commission.

The next issue involves voting procedures. The ITCF Bylaws allow any proposal that would unduly burden a particular "category of member" (defined to mean investor-owned utilities, publicly-owned utilities, non-utility generators, 31/ and cooperatively-owned utilities) to be vetoed by that category of member. The Bylaws set forth the specific circumstances required to exercise the veto. They also provide that for purposes of the veto, "any member whose membership includes more than one category of member" is entitled to a vote representing each such category. 32/ Cajun argues that this provision is ambiguous and that some members will be able to vote more than once. Cajun argues that there must be one vote per entity. 33/

W agree that the provision is not clear. However, our reading of it is that, for purposes of the veto, when a member is not an individual company, but an organization made up of at least two categories of companies, 34/ for veto purposes that organization will get a vote for each category. We do not read the Bylaws as necessarily allowing any company to vote more than

28/ This interpretation is consistent with our RTG Policy Statement, supra.

29/ ITCF filing; Bylaws, section 1.03.

30/ Cajun's July 14, 1992 motion to intervene at 12.

31/ Non-utility generators are not defined in the filed materials. However, we interpret this term to include any non-traditional entity that sells electric energy at wholesale.

32/ ITCF filing; Bylaws, section 2.02.

33/ Cajun's July 14, 1992 motion to intervene at 12-13.

34/ The Bylaws allow a group of entities to join the ITCF as a single entity. ITCF filing; Bylaws, section 1.01.

once (that is, once as an individual member and once as a member of a group that is itself a member). We cannot say at this point that this arrangement is unjust, unreasonable, or unduly discriminatory or preferential. 35/

Our review of the ITCF filing and the pleadings indicates that the filing has not been shown to be unjust, unreasonable, or unduly discriminatory or preferential. Accordingly, we will accept the filing without further investigation, to become effective September 4, 1993, as requested.

Cajun also argues that the Commission should refuse to find that the ITCF is in the public interest, as the ITCF requested. Cajun and AEC argue that the ITCF may have an anticompetitive effect. 36/ Cajun states that the Commission may lack authority to grant "immunity" from the antitrust laws.

We will not make a finding that the ITCF is or is not in the public interest. Our review of the filing is under FPA section 205, which requires only that a filing be just, reasonable, and not unduly discriminatory or preferential. This order simply concludes that the ITCF filing has not been shown to violate that standard or to necessarily have an anticompetitive effect. In reaching this conclusion, we have relied upon certain aspects of ITCF's structure and on our continuing review authority under the FPA. First, although it appears that ITCF will have the authority to take certain general actions regarding transmission operations, the ITCF voting structure permits full veto power of any resolution by only one membership category. We believe this facet of the ITCF should address some of the concerns of Cajun and AEC. Second, it appears that ITCF processes (i.e., the dispute resolution procedure) may give rise to substantive outcomes affecting both members and non-members with respect to transmission. To the extent that ITCF members or third parties are aggrieved by ITCF processes or outcomes that result from these processes, such persons may file complaints with the Commission under FPA section 206.

35/ In our Policy Statement Regarding RTGs, supra, we emphasized the need for fairness and no undue discrimination in RTG voting procedures. We also emphasized the need for flexibility (for example, "super-majority" voting rules) in order to ensure that, for instance, transmission owners do not dominate the RTG.

36/ AEC's motion to intervene at 4-7; Cajun's July 14, 1992 motion to intervene at 7-10.

The ITCF asks the Commission to allow its Administrator to make future filings on behalf of the ITCF. We will allow this procedure. 37/

Finally, the ITCF cover letter asks us to state that ITCF public utility members may resign "in accordance with the Charter and Bylaws" without Commission review. 38/ However, the Charter and Bylaws do not address resignation. We will not allow public utility members to resign without making a filing with the Commission. Resignation would involve termination of the public utility's obligations 39/ under the ITCF and as such would be a change in a contract relating to jurisdictional service under FPA section 205(c).

Although we are accepting the ITCF documents, we note that they are skeletal in nature and that the ITCF does not contain most of the elements of an RTG as defined in our recent Policy Statement. For example:

h The ITCF makes no mention of how it will coordinate and consult with State regulatory or other authorities;

h Its members do not obligate themselves to provide transmission service to each other;

h Its geographic scope has not been shown to be efficient or sufficiently contiguous;

h While the ITCF establishes a Planning Committee, it does not appear to provide for a coordinated plan to meet the reliability and economic demands on the transmission system;

h It is not clear that the governance procedures meet the standards of the Policy Statement; and

h There are no termination provisions.

37/ See 18 C.F.R. 35.1(a); also see Western Systems Power Pool, 55 FERC 61,099, 61,301 (1991), reh'g denied, 55 FERC 61,495 (1991), aff'd sub nom. Environmental Action, et al. v. FERC, No. 91-1404 (D.C. Cir. July 2, 1993).

38/ ITCF filing; Cover letter at 4.

39/ For example, members are obligated to attempt to resolve transmission operation and use issues through mediation procedures before coming to the Commission.

While the ITCF is not an RTG, but rather is a coordination group of limited scope and involving limited commitments, we do not want to discourage increased cooperation and coordination. We encourage the members of ITCF to work toward becoming RTGs as described in our recent RG Policy Statement.

The Commission orders:

(A) Ohio's motion to intervene is hereby granted.

(B) The ITCF filing is hereby accepted for filing, to become effective on September 4, 1993.

By the Commission. Commissioner Hoecker concurred in part and dissented in part with a separate statement attached.
Commissioner Massey concurred with a separate statement attached.

(S E A L)

Lois D. Cashell,
Secretary.

Interregional Transmission Coordination Forum) Docket No. ER92-667-000

(Issued September 3, 1993)

HOECKER, Commissioner, concurring in part and dissenting in part:

Although not a pessimist by nature, I view this particular vessel (ITCF's proposal) as half empty whereas my colleagues think of it as half full. For the most part, we agree on the basic facts. ITCF's repeated efforts to establish a means to address interconnected utility operations, coordination issues, compensation for parallel flows, and reliability questions -- however laudable the principles or tortuous the road to this point -- are essentially stillborn because they do not meet even the seven minimum components of our Policy Statement on Regional Transmission Groups (RTGs). Moreover, the Statement of Policy specifically states:

> The Commission encourages RTG agreements that contain as much detail as possible in all of the components listed, particularly if the RTG participants will be seeking Commission deference to decisions reached under an RTG agreement. 18 C.F.R. 2.21 (1993).

This, I submit, suggests that the ITCF filing warrants a thoughtful but firm rejection. The majority nonetheless feels compelled to accept the ITCF proposal for filing notwithstanding the imprecise and general nature of that proposal.

ITCF embodies progressive ideas, but there is nothing in the Commission's Order today that warrants the conclusion that utilities need go no farther. Today's Order leaves a number of unresolved questions.

1. Is the ITCF agreement of any practical or jurisdictional consequence?

Probably not. ITCF members have not undertaken any obligation to provide transmission service or to engage in sales for resale. In my opinion, the ITCF documents are not sufficiently comprehensive nor do they contain enough detail to merit a finding that the ITCF procedures may affect or relate to rates or services within the meaning of section 205(c). Even the majority states that "the Commission ordinarily would not require the filing of documents such as the ones in this docket." (Slip Op. at 6.) Alabama Electric Cooperative, Inc., hits the proverbial nail on the head when it argues that ITCF appears to

be seeking FERC approval of an undefined course of conduct. Similarly, the Public Utilities Commission of Ohio argues that "[t]he broad and general nature of ITCF's `petition' makes it impossible . . . to discern the purpose of the filing and the potential ramifications flowing therefrom." Cajun Electric Power Cooperative, Inc., points out significant discrepancies among the various ITCF documents -- its Charter, its Bylaws, and the accompanying cover letter -- which require substantial interpretation in order for the majority to construe these documents into something resembling a "rate filing."

2. Will the Commission's conditional acceptance of this filing satisfy ITCF and lead to constructive coordination agreements?

Doubtful. Although asking for the Commission's imprimatur, ITCF implores the Commission not to impose restrictions on the freedom of members to leave the group. The Order correctly denies that request. It is neverthelss clear that the ITCF members have only committed to voluntary, non-binding mediation and have made no commitment to even stay in the organization. I see no purpose to be served by allowing the Commission's file rooms to serve as a repository for paper reflecting the good intentions of public utilities.

3. Will the ITCF agreement form the basis of a legitimate RTG and will the Commission's action today enhance the prospects for a workable RTG among some of the ITCF membership?

Who knows? But acceptance of the ITCF filing arguably may inhibit or arrest progress toward formation of an RTG. I am fearful that, having worked hard for the general principle of coordination of transmission needs on a regional basis, ITCF members and others may well read today's order as a lowering of expectations and a willingness to entertain even the most meager of proposals. My fears are based, in part, on a belief that the ITCF, as presently constituted, may be overly comprehensive in terms of its membership and its geographic scope. I doubt that the ITCF will ever be able to satisfy the criterion contained in our Policy Statement that "an RTG agreement should encompass an area of sufficient size and contiguity to enable members to provide transmission services in a reliable, efficient, and competitive manner." To that end, I would suggest that ITCF members explore the formation of sub-regional groups -- perhaps organized along the lines of existing reliability councils within the Eastern grid -- as they continue their efforts to promote

cooperation and coordination among the owners, operators, and users of the interconnected transmission system. In my opinion, such sub-regional groups, built from existing institutions, have a much greater chance of achieving a consensus thatwill lead to workable RTG agreements consistent with the Commission's recent Statement of Policy.

James J. Hoecker
Commissioner

Interregional Transmission Coordination Forum) Docket No. ER92-667-000

(Issued September 3, 1993)

MASSEY, Commissioner, concurring:

It is my observation that the Commission remains firmly and vigorously committed to the policy of encouraging the formation of RTGs. Nothing in this order should be construed to the contrary.

William L. Massey
Commissioner

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BYLAWS

WESTERN REGIONAL TRANSMISSION ASSOCIATION

Part 2 of 3 Parts

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PREAMBLE

Voluntary associations, such as this Western Regional Transmission Association (Association), are intended to facilitate the efficient use of existing transmission facilities, coordinate the planning of transmission system expansions and expedite the resolution of disputes.

Pursuant to these Bylaws, Members agree to promote coordinated transmission planning, efficient use of transmission capacity, nondiscriminatory access to transmission facilities and fair pricing for transmission services.

1. PURPOSE.

The Association is a voluntary organization of Transmission Providers, Transmission Users and Commissions located throughout the Western Interconnection. Members have formed the Association to foster the efficient, equitable and reliable use of existing and future transmission facilities and the expeditious and fair resolution of disputes related to transmission access. The Association shall, in cooperation with the WSCC, provide a forum for coordination of transmission planning and for the exchange of information to assist Members in meeting their transmission needs.

2. DEFINITIONS.

When capitalized herein, whether in singular or plural, the following terms shall have the following meaning:

2.1 Arbitrator. An individual selected to resolve disputes arising under these Bylaws pursuant to Section 12.

2.2 Arbitration Committee. The Committee described in Subsection 6.7.

2.3 Available Transmission Capacity. That amount of transmission capacity available to a Transmission Provider to provide transmission service to a Transmission User which is not reasonably required to accommodate the Transmission User's: (i) Native Load; (ii) existing commitments for firm wholesale sales contracts; (iii) existing contractual and statutory commitments for firm transmission service; and (iv) Prudent Reserve.

2.4 Award. A decision of an Arbitrator made pursuant to Subsection 12.3 of these Bylaws.

2.5 Board. The Association's Board of Directors, as described in Section 5.

2.6 Commissions. State or provincial utility regulatory commissions or energy commissions.

2.7 Committee. A Committee of Members established pursuant to these Bylaws or by the Board.

2.8 Existing Facilities. Those transmission facilities owned by a Member or under contract to a Member that have been used to transmit electric energy.

2.9 FERC. The Federal Energy Regulatory Commission or a successor agency.

2.10 FPA. The Federal Power Act as it may be amended from time to time.

2.11 Incremental Facilities. Transmission facilities, other than Existing Facilities, that are reasonably required to be used to satisfy a request for transmission service from a Transmission User.

2.12 Interconnected Transmission System. That portion of each Transmission Provider's transmission system utilized for bulk power transactions, generally at voltages of 115 kV and higher.

2.13 Member. Any signatory to these Bylaws which is a Transmission Provider, a Transmission User or a Commission operating or located in the Western Interconnection.

2.14 Native Load. Load associated with retail customers and full or partial requirements wholesale customers for which a Transmission Provider, by statute, franchise, contract or FERC policy or regulation, has undertaken the obligation to plan, construct and operate its system to provide reliable service.

2.15 Planning Committee. The Committee described in Subsection 9.1.

2.16 Power Marketing Agency. The Western Area Power Administration or the Bonneville Power Administration.

2.17 Prudent Reserve. An amount of transmission capacity set aside for a Transmission Provider's reasonable reliability requirements as determined by the reliability criteria of such Member and consistent with Prudent Utility Practice and

regional reliability council criteria, which requirements shall be impartially applied without undue discrimination.

2.18 Prudent Utility Practice. Those practices, methods and acts, including levels of reserves and provisions for contingencies, as may be modified from time to time, that are commonly used in the Western Interconnection to: (i) operate electric systems dependably, reliably, safely, efficiently, economically and in accordance with all applicable laws and governmental rules, regulations and orders; (ii) serve customers; and (iii) prevent material adverse effects on neighboring electric systems.

2.19 Subregional Coordination Groups. Voluntary subregional associations involving Members that may be organized from time to time to exchange information and coordinate local transmission planning in subregions of the Western Interconnection whose policies and activities are not inconsistent with these Bylaws.

2.20 Transmission Provider. Any Member owning or having contractual rights to use transmission facilities located in the Western Interconnection.

2.21 Transmission User. Any Member entitled to apply to the FERC for an order requiring transmission services pursuant to Section 211 of the FPA.

2.22 Western Interconnection. The area comprised of those states and provinces in Western Canada, Northern Mexico and the Western United States in which Transmitting Utilities,

which are members of the WSCC, operate synchronously connected transmission systems.

2.23 WSCC. The Western Systems Coordinating Council.

3. MEMBERSHIP.

3.1 Qualifications. Any entity meeting the definition of a "Member," set forth in Subsection 2.13, shall be admitted to membership in the Association upon executing these Bylaws and providing notice of its having done so to the FERC.

3.2 Classifications of Members. Upon being admitted for membership, each Member shall designate which of the following classifications of Members to which it wishes to be assigned:

a. Major Transmitting Utility

b. Transmission-Dependent Utility

c. Nonutility Supplier

d. Commission

3.3 Membership Responsibilities. Each Member, other than a Commission, shall:

3.3.1 Conduct or participate in joint studies which affect such Member's system; provided, however, no Member shall be required to participate in a study exclusively related to its own system that is initiated by another party.

3.3.2 Provide necessary information, data and plans as specified by the Planning Committee to assure coordinated planning of transmission projects.

3.3.3 Provide full and timely responses to requests for transmission service as specified in Section 10.

3.3.4 In regard to transmission service requests at 69 kV or lower voltages, or for other facilities for which the Association does not collect data, provide to the Transmission User, or other Members, system data necessary to conduct system studies, if so desired by the Transmission User or other Members.

3.3.5 Pay its share of administrative and planning costs as described in Section 8 below.

3.3.6 Make its employees available for reasonable periods at no cost to serve as facilitators or Arbitrators of disputes among Members arising out of the application of these Bylaws.

3.4 Withdrawal from Membership. Any Member may withdraw from the Association upon providing written notice of its withdrawal to the Board and the FERC. Notwithstanding such notice of withdrawal, all Awards and requests for transmission service to be provided by such Member in effect or pending as of the date of the receipt of written notice of withdrawal shall be followed to completion, pursuant to these Bylaws by the withdrawing Member; however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of these Bylaws. Any Member which has voluntarily withdrawn from the Association may not reapply for Membership for a period of one year from the date of its withdrawal.

3.5 Termination of Membership. At any time that a Member becomes delinquent in the payment of any administrative and operating costs which are incurred during its membership and fails after 90 days of receipt of a written notice to pay such costs, or if the Board finds that a Member has: (i) intentionally or repeatedly violated any Bylaw of the Association, (ii) breached or violated any Award issued pursuant to its membership in the Association, or (iii) willfully obstructed any lawful purpose or activity of the Association, the Board, in its sole discretion, may terminate the Member's membership. The affected Member shall be afforded at least 21 days advance written notice of any Board meeting at which termination of the Member will be considered and such Member shall have the right to be present and present information to the Board concerning any proposed termination action. Upon termination of membership, all of the Member's voting rights and other rights of membership shall cease. Notwithstanding such notice of termination, all Awards and requests for Firm Transmission Service to be provided by such Member in effect or pending as of the effective date of termination shall be honored by the terminated Member; however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of these Bylaws. A Member which has been terminated from membership may not reapply for membership for a period of time stated in the Board resolution of termination, which shall not exceed a period of five years.

4. MEETINGS OF MEMBERS.

4.1 Annual Meeting. A meeting of the Members shall be held within 60 days of the effective date of these Bylaws and thereafter at least annually, within the Western Interconnection on a date and at a time and place fixed by the Board.

4.2 Notice of Meeting. Written notice of every meeting of the Members shall be prepared and mailed to the last known address of each Member not less than 21 nor more than 60 days before such meeting. Such notice shall state the time and place of the meeting and the meeting agenda.

4.3 Voting. Each Member, other than a Commission, shall be entitled to one vote upon each matter submitted to a vote at a meeting of the Members. Except in regard to the election of Directors, all matters coming before the Membership shall require the affirmative vote of two-thirds of the Members of each voting Membership classification present at the meeting in order to be adopted.

4.4 Quorum. A majority of the total number of Members with voting rights shall constitute a quorum necessary for the transaction of business at any annual or special meeting of the Members. Those Members present may adjourn from time to time until a quorum is present with no further notice of the meeting required.

5. GOVERNANCE.

5.1 Board of Directors. The Association shall have a Board of Directors comprised of 21 Directors. Directors shall be selected from among the three classifications of voting Members and each such classification shall be entitled to vote upon and be represented by the following number of Directors:

a. Major Transmitting Utilities 7

b. Transmission-Dependent Utilities 7

c. Nonutility Suppliers 7

5.2 Ex-Officio Directors. Commission Members shall select three Directors to serve in an ex-officio status on the Board. Such ex-officio directors shall be invited to attend and participate in all meetings of the Board, and Committees, but shall not have a right to vote on matters coming before the Board or Committees.

5.3 Diversity of Directors. Each Director in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have his or her principal place of business in a different state or province, provided, however, two directors in any classification may be from California. No more than one Director may be employed by or be affiliated with any Member. At least three of the Directors in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have their principal place of business in the states of Texas, Arizona, New Mexico, California, Nevada or the states of Mexico and at least three of the Directors in the Major Transmitting Utilities and Transmission-Dependent

Utilities classifications shall have their principal place of business in the states of Oregon, Washington, Idaho, Montana, Utah, Wyoming, Colorado or the provinces of British Columbia or Alberta.

5.4 Election of Directors. At each annual meeting of the Members, elections shall be held to fill any vacancies on the Board. Directors shall be selected from within each classification for each position by a plurality vote of the Members of that classification. No person may be nominated for a Director position if his or her election would violate the provisions of subparagraph 5.3. Except as applied to the initial Board, Directors shall be elected for terms of three years and until a successor is elected and qualified. The initial Board shall determine the length of each Director's term by drawing lots, with seven Directors serving terms of three years, seven Directors serving terms of two years, and seven Directors serving terms of one year.

5.5 Removal of Directors and Vacancies. An individual Director may be removed from office by and at the discretion of a Member employing the Director or by majority vote of the classification of Members represented by the Director to be removed. Whenever a vacancy occurs, other than from expiration of a term of office, a Director's remaining term shall be filled by majority vote of the remaining Directors representing the class of Members whose Director's position became vacant until the next annual meeting at which time it shall be filled

by a plurality vote of the classification represented by such Director.

5.6 Annual Board Organizational Meeting. A meeting of the Board shall be held at the conclusion of each annual meeting of the Members for the purpose of electing the officers of the Association for the upcoming year and to transact such other business as may come before the meeting.

5.7 Regular Meetings. Regular meetings of the Board, in addition to its annual meeting, shall be held upon such notice and at such time and place as the Board may determine. The Board may hold meetings by conference call.

5.8 Special Meetings. A special meeting of the Board shall be held whenever called by the President or, during the President's absence or disability, by the Vice President, on notice delivered by first class mail or facsimile at least seven days prior to the meeting. Special meetings shall be called by the President or Secretary in like manner and on like notice on the written request of any four Directors.

5.9 Quorum and Voting. Two-thirds of the Directors in each voting membership classification shall constitute a quorum necessary to the transaction of business at any meeting of the Board. All matters coming before the Board shall require the affirmative vote of two-thirds of each voting class of Directors. By providing advance written notice to all other Directors, a Director may designate an alternate to attend any

Board meeting and such alternate shall have full authority to act and vote in place of the absent Director.

5.10 Action Without a Meeting. Any action which may be taken at a meeting of the Board, or of a Committee, may be taken without a meeting if set forth and approved by a writing signed by all Directors or Committee members, and such action shall be effective on the date on which the last signature is placed on such writing, or such earlier effective date as is set forth therein.

6. DUTIES OF DIRECTORS.

6.1 General Powers. The Board shall manage the business and affairs of the Association, and shall exercise all of the powers of the Association except such as are by law or these Bylaws conferred upon or reserved to the Members. The Board shall recommend any amendments to the Bylaws for approval by the Members and may adopt such policies, rules, regulations, and actions which are consistent with law and these Bylaws as it may deem advisable.

6.2 Selection of Manager and Agents. The Board shall select and employ a Manager and fix the compensation of such Manager. The Board may terminate the employment of the Manager with or without cause at any time. The Board shall also have authority to authorize the employment of other staff members or retain agents to provide defined activities and services.

6.3 Budgets. The Board shall periodically establish and approve a budget which includes all costs of administration for

the Association as well as any anticipated planning costs to be allocated to the Members. Such budgets shall be established and approved not less than annually.

6.4 Accounting System and Audit. The Board shall install and maintain an adequate system of accounts and records. At least annually, the books and accounts of the Association shall be audited by a certified public accountant and the report of such audit shall be made at the next annual meeting of the Members.

6.5 Committees. The Board shall appoint or terminate Committees as it deems appropriate. Membership on all Committees appointed by the Board shall be allocated among membership classifications and geographic regions on generally the same proportional basis as required for Board membership. The organizational form and term of Committee chairpersons and other positions shall be established by the Board. Reasonable advance notice of all Committee meetings shall be given to all Members. Attendance at all Committee meetings shall be open to any Member: provided that only Committee members from membership classifications with voting rights shall have the right to vote on matters coming before the Committee. Matters coming before Committees shall be resolved by a majority vote of Committee members voting.

6.6 Planning Committee. The Board shall appoint a Planning Committee whose function is described in Section 9.1. The Membership of the Planning Committee shall include the

Chairpersons of all Subregional Coordination Groups. Three members of the Planning Committee, representing the Transmission-Dependent Utility, Nonutility Supplier and Commission classifications, respectively, shall be designated by the Planning Committee to serve as liaisons with the planning committees of the WSCC and to otherwise represent the interests of members who are not WSCC members.

6.7 Arbitration Committee. The Board shall appoint an Arbitration Committee consisting of one representative of each of the three voting Membership classifications. The Arbitration Committee shall have the responsibilities described in Subsection 6.9 and Part 12.2.1 and shall also, from time to time, review the arbitration procedures set forth in these Bylaws and consider proposed changes to be presented to the Board.

6.8 Other Committees. The Board may authorize such additional committees as it deems necessary to carry out the business of the Association. The Board shall set forth the duties and responsibilities of each such Committee in writing at the time of the creation of the Committee. Each such Committee shall be subject at all times to control and direction of the Board. Copies of the minutes of each such committee meeting shall be mailed to all Directors.

6.9 Qualified Arbitrators. The Board shall establish and from time to time update a list of qualified Arbitrators who are employed by Members. The list of Arbitrators may be

subdivided by the Arbitration Committee into specific types of disputes that an Arbitrator is considered to be qualified to decide or by subregional areas concerning which an Arbitrator has expertise. All arbitrators supplied by the Arbitration Committee pursuant to Part 12.2.1 shall be taken at random from the Board-approved list or subdivisions of that list.

6.10 Subregional Coordination Groups. The Board shall review bylaws of proposed Subregional Coordination Groups and determine whether the policies and activities of such groups are consistent with these Bylaws. Upon an affirmative determination by the Board in regard to such bylaws, the Subregional Coordination Group shall be recognized as such by the Association and afforded the benefits of Subsections 6.6, 9.1 and 9.16.

7. OFFICERS AND MANAGER.

7.1 Election of Officers. At each annual meeting of the Board of Directors, the Board shall elect a President, a Vice President, a Secretary and a Treasurer. The President and Vice President shall be Directors of the Association. An officer may be removed by the Board whenever in its judgment the best interests of the Association will be served thereby. If any vacancy shall occur among the officers of the Association, it shall be filled by the Board of Directors at its next regular meeting following the vacancy.

7.2 Duties of President. The President shall:

(i) preside over all meetings of the Association and the Board;

(ii) call special meetings of the Board; and (iii) perform all duties that may be reasonably required of him by the Association or the Board.

7.3 Duties of Vice President. In the absence or disability of the President, the Vice President shall perform the duties of the President.

7.4 Duties of Secretary. The Secretary shall attend all meetings of the Board and all meetings of the Members and record all votes and keep a complete record of all meetings of the Association and of the Board and shall have general charge and supervision of the books and records of the Association. The Secretary shall sign all papers pertaining to the Association as may be authorized or directed by the Board. The Secretary shall serve all notices required by law and by these Bylaws including notices of meetings and shall make a full report of all matters and business pertaining to the office to the Members at the annual meeting. The Secretary shall make all reports required by law and shall perform such other duties as may be requested by the Board.

7.5 Duties of Treasurer. The Treasurer shall perform such duties with respect to the finances of the Association as may be prescribed by the Board.

7.6 Duties of Manager. The Manager shall perform such duties and shall exercise such authority as the Board may from time to time vest. The Manager shall put in place and maintain Association newsletters and/or an electronic bulletin board

sufficient to keep Members timely informed of events related to Members' activities carrying out the purposes of these Bylaws.

7.7 Compensation. The salary, compensation and other benefits of the Manager and any other staff shall be fixed by the Board. No member of the Board shall receive any compensation or other benefits.

8. MEMBER COSTS.

8.1 Administrative Costs. The administrative costs of the Association shall be allocated as follows:

8.1.1 25% of the total costs shall be allocated among the Members, other than Commissions, on a per capita basis, and

8.1.2 75% of the total costs shall be allocated among the Members based upon total revenues from the sale of electricity.

8.2 Planning Costs. The costs of planning studies or other activities, if undertaken by the Association, shall be generally allocated among the Members benefitting from such activities in proportion to the amounts of transmission capacity in megawatts desired by each participating Member. Specific activities and cost allocations may be memorialized in separate agreements among the participating Members.

9. COORDINATED PLANNING AND ACCESS.

9.1 Planning Committee Functions. The Board shall appoint a Planning Committee. The Planning Committee shall provide a forum for coordination of transmission planning

activities within the Association by facilitating the prompt exchange of information among Members through use of a common data base in order to: (i) assist timely responses by Members to requests for transmission service, (ii) assist the development of coordinated transmission plans to serve the needs of all Members, and (iii) support the Association's interface with WSCC, other industry organizations and Subregional Coordination Groups. To carry out these responsibilities, the Planning Committee, in conjunction with the WSCC, shall:

9.1.1 Provide a forum for coordinating transmission plans, sharing system data, facilitating the joint development of new transmission projects, and meeting the transmission facility planning needs of Members.

9.1.2 Collect, or cause to be made available, Member information, data and transmission plans as determined by the Planning Committee in order for the Association to meet its objectives.

9.1.3 Collect and make available to all Members the internal planning criteria of individual Members.

9.1.4 Ensure that new project transmission studies and information are available to all Members who request it.

9.1.5 Prepare appropriate Association planning information reports and maps for government regulatory agencies, reliability councils and others, as requested, including coordinating Transmission Providers' reports to the

FERC required by rules promulgated pursuant to Section 213(b) of the FPA.

9.1.6 Refer to Subregional Coordination Groups matters having principally subregional interest.

9.1.7 Periodically review and make recommendations to the Board concerning the procedures for obtaining transmission services provided for in these Bylaws.

9.1.8 Carry out other activities as directed by the Board.

9.2 Planning Information. Each Transmission Provider shall file on an annual basis with the Planning Committee information regarding its existing and planned Interconnected Transmission System. The Planning Committee shall determine what data are required, including the years for which the data are to be reported and the format of the data, to assure that the objectives of the Association are met. The data submitted by each Transmission Provider for its Interconnected Transmission System shall be consistent, to the extent feasible, with the format established by the WSCC and shall include, at a minimum, data necessary to comply with Section 213(b) of the FPA and rules and regulations promulgated thereunder.

9.3 Planning Coordination.

9.3.1 No member shall be required to implement a planning recommendation made by the Planning Committee or the Board; provided, however, no member shall be relieved of its

obligation to respond to requests for transmission services as required by these Bylaws or to implement the provisions of an Award.

9.3.2 Members involved in the development of transmission projects that may interconnect two or more utility systems shall provide notice of opportunity to participate in development study work to all Members by posting in the Association's newsletter or electronic bulletin board. Members shall respond in writing to the sponsoring Members within 60 days after notice is posted indicating whether they elect to participate in such studies. Those Members participating in joint project studies shall periodically share the results of the study work with the Planning Committee.

9.3.3 Costs for joint planning studies shall be shared on an equitable basis among those Members participating in the studies. Study costs may include computer costs, staff time, report preparation, report distribution and appropriate overhead costs, as applicable.

9.3.4 Arrangements among participating Members for joint studies shall be documented by letter agreement or other appropriate instrument prior to the beginning of the studies.

9.4 Interface with WSCC. In order to avoid unnecessary duplication, Transmitting Utilities shall utilize WSCC reports and data to the maximum extent practicable to fulfill the information reporting requirements set forth in Subsection 9.2. The Planning Committee shall develop standard forms, if not

already available, which Transmitting Utilities can use to fulfill reporting requirements for the WSCC, the Association and the FERC. All data collected directly by the Association, or in cooperation with the WSCC, shall be reasonably available to all Members through the Association regardless of its physical location.

9.5 Planning Criteria.

9.6.1 The applicable reliability criteria, standards, guidelines and operating procedures of the North American Electric Reliability Council, the WSCC, other electric reliability councils, and of the individual Transmission Provider shall govern the design and operation of each such Member's transmission system. Individual Transmitting Utilities' reliability criteria, standards, guidelines and operating procedures shall be reasonable and consistent with Prudent Utility Practice and shall be consistently applied.

10. REQUESTS FOR TRANSMISSION SERVICE.

10.1 Service to be Provided. Subject to the provisions of Section 14, each Transmission Provider shall provide transmission service from its Available Transmission Capacity on its Existing Facilities, or from Incremental Facilities where necessary, to any Transmission User on a basis consistent with the FPA and with FERC's standards and policies and as detailed in the Transmission Provider's applicable tariff, or an agreement negotiated between such Members or established through Arbitration, if such tariff does not exist. Canadian

or Mexican Transmission Providers may establish prices based upon policies different than, but no less favorable to Transmission users, than those established by the FERC. Members not subject to Section 211 of the Federal Power Act nonetheless agree to provide transmission service on the same basis as those that are Members that are subject to such requirements.

10.2 Tariff or Agreement Required. Transmission service shall be provided solely under a separate tariff or agreement and these Bylaws shall not, in and of themselves, be construed to be a tariff or service agreement providing for transmission service.

10.3 Request for Service. Each Transmission User desirous of transmission services shall, in each instance, pursue its request for such service pursuant to these Bylaws in lieu of exercising its procedural rights pursuant to Section 211 of the FPA. A Transmission User requesting transmission service shall provide to the Transmission Provider information regarding its request for transmission service, consistent with either the FERC's then current policy regarding such request (as currently embodied in its "Policy Statement Regarding Good Faith Requests for Transmission Services") or the tariff of the Transmission Provider under which transmission service is sought.

10.4 Response to Request for Firm Transmission Service.

10.4.1 The Transmission Provider shall respond to a request for transmission service from a Transmission User in a manner consistent with Section 212 of the FPA and FERC's then current policies (as presently embodied in its "Policy Statement Regarding Good Faith Requests for Transmission Services").

10.4.2 The Transmission Provider may elect to provide the requested transmission service, or to conduct a study, including any required environmental studies, if such is reasonably required, at the Transmission User's expense, to determine: (i) whether it has sufficient Available Transmission Capacity to provide the requested service initially and for the full term of the request and (ii) what upgrades, additional transmission facilities or interconnections are required to accommodate the requested service. The Transmission Provider's reasonable study costs shall be billed to and paid by the Transmission User in advance based upon the Transmission User's reasonable estimate of such costs. Any reconciliation for over or underpayment shall be done upon completion of the study work. Such study shall be completed within a reasonable time period, as agreed to by the Transmission Provider and Transmission User or, if such Members cannot agree, as determined by the Planning Committee. The Transmission Provider shall be responsible for conducting the study with participation and input from the Transmission User, as mutually agreed to, and

the results of the study shall be made available to the Transmission User, the Coordination Committee, and any other Member requesting it.

10.5 Requests Requiring Upgrades, Additional Facilities or Interconnections.

10.5.1 If the Transmission Provider's report issued at the completion of a study performed pursuant to Subsection 10.4 concludes that the Transmission Provider does not have sufficient Available Transmission Capacity to provide the requested service initially or for the term of the request, it shall include at a minimum: (i) the estimated cost of and cash flow requirements for installing the necessary facilities or providing the interconnection; (ii) the estimated time necessary to build such facilities or provide such interconnection, including the estimated time required for environmental studies, licensing and regulatory approvals, and (iii) the estimated incremental capacity added to the transmission system by the additional facilities.

10.5.2 If the study results demonstrate a need for a transmission interconnection with another entity, the Transmission Provider shall make a good faith effort to arrange a joint study with the other entity to evaluate the impact of such an interconnection. Costs for this additional study shall also be borne by the Transmission User.

10.5.3 If the study results demonstrate a need for and the feasibility of building new facilities or providing an

interconnection, the Transmission User may elect to have the required facilities constructed by the Transmission Provider. The Transmission Provider shall be obligated to build the project based upon the conditions outlined in the Transmission Provider's report and an agreement negotiated between the Transmission Provider and the Transmission User, subject only to state and provincial law, the FPA and FERC's standards and policies. The Transmission Provider shall provide notice of the project to all Members through posting in the Association newsletter or electronic bulletin board.

11. PRICING.

Pricing of transmission service by a Transmission Provider in response to any request for transmission service shall utilize pricing procedures and methodologies for use of Existing Facilities and Incremental Facilities (if applicable) in a manner consistent with the FPA and the then-established standards and policies of the FERC or as provided for in existing FERC-approved tariffs, where extant. Transmitting Utilities in Canada or Mexico may rely upon pricing policies of regulatory bodies other than the FERC if such policies are no less favorable to Transmission Users than those of the FERC. Notwithstanding the foregoing, any Transmission Provider may, from time to time, request through a petition for declaratory ruling, or request for rulemaking, that the FERC find a particular form of transmission pricing just and reasonable;

provided, however, pending the resolution of such petition or request, established policies shall govern.

12. DISPUTE RESOLUTION.

12.1 Preconditions to Arbitration.

12.1.1 Members shall make best efforts to settle all disputes associated with transmission access or services, including but not limited to, disputes concerning amounts and location of Available Transmission Capacity, as well as costs, prices, and terms and conditions of transmission service. In the event any such dispute is not settled, any disputing Member may request in writing that the Manager appoint an impartial facilitator from the Association membership to aid the disputing Members in reaching a mutually-acceptable resolution to the dispute and such appointment shall be made within ten days. The facilitator and representatives of disputing Members with authority to settle the dispute shall meet within 21 days after the facilitator has been appointed to attempt to negotiate a resolution of the dispute. A resolution may consist of referring the matter to another body for resolution or an advisory opinion.

12.1.2 If the disputing Members have not succeeded in negotiating a resolution of the dispute within 30 days after first meeting with the facilitator pursuant to Paragraph 12.1.1, such Members shall be deemed to be at impasse and commence the binding arbitration process.

12.1.3 Disputes related to the interpretation or performance of executed agreements or service schedules that have been approved or accepted for filing by the FERC shall not be subject to Arbitration under these Bylaws unless otherwise agreed by the disputing Members.

12.2 Binding Arbitration Process.

12.2.1 Within 14 days of the disputing Members' reaching impasse, each disputing Member shall submit a statement in writing to the other disputing Members, which statement shall set forth in reasonable detail the nature of the dispute, the issues to be arbitrated, and the proposed Award sought through such arbitration proceedings. To the extent disputing Members do not agree on a form of a required contract for transmission service, each submittal shall include proposed contract language for those issues in dispute. These statements shall constitute the sole submittal of statements for arbitration. A summary of such statement of issues shall be published in the Association's newsletter or electronic bulletin board.

12.2.2 Within ten days following the submission of their statements, the disputing Members, shall select an Arbitrator. The arbitration shall be conducted by a an Arbitrator familiar with and knowledgeable about the policies and criteria used in the Western Interconnection, transmission systems, and regulatory requirements. If the disputing Members cannot agree upon an Arbitrator, each disputing Member shall

take turns striking names from a list of ten qualified individuals supplied by the Arbitration Committee from the list maintained by the Board pursuant to Subsection 3.9 with a disputing Member chosen by lot first striking a name. The last-remaining name not stricken shall be designated as the Arbitrator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected who is able and willing to serve. No person shall be eligible for selection as an Arbitrator who is a past or present officer, member of the governing body, employee or consultant of any of the disputing Members, or of an entity related to or affiliated with any of the disputing Members or is otherwise interested in the matter to be arbitrated. Any individual designated as an Arbitrator shall make known to the disputing Members any such disqualifying relationship and a new Arbitrator shall be designated in accordance with the provisions of this subparagraph.

12.2.3 The Arbitrator shall determine what arbitration procedures shall apply, consistent with these Bylaws, taking into account the complexity of the issues involved, the extent to which factual matters are disputed and the extent to which the credibility of witnesses is relevant to a resolution. The Arbitrator shall consider all issues underlying a dispute including, if relevant, the reasonableness of a disputing Transmitting Utility Member's reliability criteria; provided,

that reliability criteria which are based upon regional reliability council criteria in effect as of January 1, 1994 shall be afforded a rebuttable presumption of reasonableness and consistency with Prudent Utility Practice by the Arbitrator. The Arbitrator may elect to resolve the disputed matter solely on the basis of written submittals.

12.2.4 The Arbitrator shall take evidence submitted by the disputing Members in accordance with procedures established by the Arbitrator and may request additional information including the opinion of recognized technical experts. Such additional information shall be furnished by the disputing Member or other Members having such information. Disputing Members shall be afforded a reasonable opportunity to rebut any such additional information. Other interested Members may request in writing that the Arbitrator consider additional information and the Arbitrator may consider such additional information, subject to a right of the disputing Members to have a reasonable opportunity to rebut such additional information.

12.3 Award. Within 115 days of his or her selection as Arbitrator, the Arbitrator shall select, by written notice to the disputing Members, the proposed Award of a disputing Member which best meets the terms and intent of these Bylaws and conforms with the FPA and FERC's standards and policies. A written decision explaining the basis for the Award shall be provided by the Arbitrator with the written notice to parties.

Both notice and decision shall be published in the Association's newsletter or electronic bulletin board. No Award shall be deemed to be precedent that is binding on an Arbitrator in any other arbitration related to a different dispute.

12.4 Compliance and Costs. Immediately upon the decision by the Arbitrator, the disputing Members shall take whatever action is required to comply with the selected Award to the extent the selected Award does not require regulatory action and shall pursue no avenue of appeal, except as provided for in Subsection 12.5. To the extent the Award requires state or provincial regulatory action, FERC review of an Award involving a Power Marketing Agency or a FERC filing by a Transmission Provider subject to FPA Sections 205 or 206, the affected Member shall submit and support that portion of the Award with the appropriate regulatory authority. Any and all costs associated with the arbitration shall be borne by the Member or Members whose proposed Award was not selected, unless the disputing Members agree to an alternate method of allocating costs.

12.5 FERC Appeal. A disputing Member may apply to the FERC to hear an appeal of any Award only upon the grounds that the Award is contrary to or beyond the scope of these Bylaws or is unjust, unreasonable, unduly discriminatory or preferential or otherwise inconsistent with the FPA or FERC's standards or policies. The Members hereby agree that in the event of an application to hear an appeal of an Award, the FERC may elect

to not hear such an appeal. No Member shall seek judicial review of a FERC order declining to hear an appeal and no FERC decision not to hear an appeal shall be construed as reflecting a FERC decision on the merits or be otherwise considered precedential. If the FERC fails to act on an application for an appeal within 90 days, it shall be deemed to have agreed to hear the appeal. Any such appeal shall be based upon the record assembled by the Arbitrator, but no deference shall be afforded to the conclusions or judgments of the Arbitrator. Appeals to FERC filed on behalf of entities not otherwise subject to the jurisdiction of the FERC shall be deemed to involve an application for an order requiring transmission service pursuant to Section 211 of the FPA and shall be filed by the Transmission User on behalf of the appealing Member regardless of whether the Transmission User is the appealing Member involved in the dispute. If the FERC undertakes to hear a Member's appeal, judicial review of the FERC's resulting order may be sought from a court of competent jurisdiction.

12.6 Procedure for Appeals. Any disputing Member wishing to appeal an Award shall cause a fully-documented application to be filed with the FERC within 14 days of the entry of the Award, including a copy of the Award and the Arbitrator's decision. A summary of such an application shall be published in the Association's newsletter or electronic bulletin board. Any Member wishing to respond to such an application shall do so within 14 days. The implementation of an Award shall be

stayed pending appeal if the FERC issues an Order agreeing to hear the appeal within 60 days of the initial application for an appeal or if the FERC or a court of competent jurisdiction issues an order staying implementation.

13. NO MANDATORY RETAIL WHEELING.

No Arbitrator shall select and no Member consents to an Award which requires the transmission of electric energy under circumstances where the FERC is precluded from ordering transmission services pursuant to Subsection 212(h) of the FPA.

14. EFFECT OF BYLAWS.

These Bylaws shall not, in and of themselves, be construed as a tariff, rate schedule or service agreement providing for transmission service. These Bylaws shall not be construed as an agreement of any Member to provide transmission services of a type of under circumstances that would not be required by the FERC pursuant to FPA Section 211. Nothing in these Bylaws shall be construed as affecting the right of any Member to unilaterally make application to FERC for a change in rates or rate methodologies under Sections 205, 206 and 306 of the FPA.

15. AMENDMENTS.

Subject to approval of the FERC, these Bylaws may be amended at any annual or special meeting of the Members.

16. MISCELLANEOUS PROVISIONS.

16.1 Limitation on Liability. Subject to any applicable state and federal law which may specifically limit a Member's ability to enter into this Section, no Member, its directors,

members of its governing bodies, officers or employees shall be liable to any other Member or Members for any loss or damage to property, loss of earnings, revenues, personal injury, or any other direct, indirect, or consequential damages or injury which may occur or result from the performance or nonperformance of these Bylaws, including any negligence arising thereunder. It is the express intent, understanding and agreement of the Members that the remedies for nonperformance expressly included in these Bylaws shall be the sole and exclusive remedies available thereunder for any nonperformance of obligations under these Bylaws.

16.2 No Third-Party Beneficiaries. Nothing in these Bylaws shall be construed to create any duty to, any standard of care with reference to, or any liability to any third party.

17. FERC REVIEW.

17.1 Filing. These Bylaws shall be filed with the FERC by one or more public utilities in the Western Interconnection that are subject to the FERC's jurisdiction under Section 205 of the FPA. In such filing the FERC shall be requested to:

(a) Find these Bylaws, as written, to be in the public interest;

(b) Expressly approve the provisions of these Bylaws related to obtaining membership (Subsection 3.1), termination of membership (Subsections 3.4 and 3.5) and termination of the Association (Section 18) and find that the FERC notice provisions provided for therein shall be effective

to initiate membership, terminate membership and terminate the Association consistent with the FPA and the FERC's rules and regulations thereunder; and

(c) Expressly approve the dispute resolution provision of Section 12 and the procedures for FEPC appeal set forth therein.

17.2 Absence of FERC Approval. If the FERC issues an order requiring material changes to these Bylaws or omitting any of the findings or approvals set forth in Subsection 17.1, these Bylaws shall have no further force or effect.

18. TERMINATION OF ASSOCIATION.

The Association shall automatically go out of existence and these Bylaws shall have no further force or effect at such time, more than one year following the effective date of these Bylaws, that there are fewer than ten Members who are Transmission Providers or Transmission Users. Such termination shall be effective upon the Secretary providing written notice of such termination to the FERC.

PDX3-36538

September 28, 1993

WESTERN REGIONAL TRANSMISSION ASSOCIATION BYLAWS

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ERRATA, QUESTIONS, AND SUGGESTIONS

(References given below are to redlined version of 9/21/93)

TEXTUAL ERROR CORRECTIONS

2.3 At line 5: ". . . Transmission ~~User's~~ Provider's"
At line 8: ". . . for ~~firm~~ transmission service . . . "

2.22 At line3: ". . . ~~T~~transmitting ~~U~~utilities. . ."

2.xx Note:
- Add membership class definitions.

3.5 At line 19: ". . . ~~Firm T~~ransmission ~~S~~ervice . . ."

6.7 At line 5: "~~12.1.1~~ 12.1.2"

6.10 At line 3: " . . . the bylaws, policies and activities . . ."

At line 8: ". . .~~9.16~~ 9.1.6".

7.2 At line 4: ". . . required ~~of him~~ by the Association . . . " from the sentence.

9.4 At line 2: ". . . duplication, ~~Transmitting Utilities~~ Transmission Providers shall . . ."

9.6.1 At line 7: ". . . ~~Transmitting Utilities'~~ Transmission Provider's . . . "

10.1 At line 13: ". . . Transmission ~~u~~Users . . . "

12.2.2 At line 11: ". . . ~~3.9~~ 6.9. . ."

SUGGESTED CLARIFICATIONS

2.14 At line 4: " . . . franchise, contract or ~~FERC~~ federal, state, or provincial policy or regulation, has undertaken . . . "

7.1 At line 3: "The President and Vice President shall be chosen from the Directors . . ."

12.5 At line 14: "Any such appeal shall be base solely upon the record"

DISCUSSION ITEMS

WSCC Relationship

1. At line 8: " . . . Association shall, ~~in cooperation with WSCC,~~ provide a forum for coordination of transmission planning . . . "

9.1.5 At line 1: "Prepare, when appropriate, Association planning information . . ."

9.4 At line 5: "The Planning Committee shall develop standard forms, ~~if not already available,~~ which ~~Transmitting Utilities~~ Transmission Providers can use . . . "

Comment:

- There continues to be concern for ending up with parallel and competing planning activity. There is also a concern that FERC's policy statement requires explicit provisions on how planning is to occur. One suggestion to add the following at the end of this subparagraph:
  "Planning activities of the Association and Subregional Coordination Groups shall be performed, to the extent feasible, consistently with WSCC planning standards and procedures."

Subregional Coordination Groups

2.19 At line 9: ". . . whose policies and activities are ~~not in~~consistent with ~~these bylaws~~ FERC criteria for Regional Transmission Groups."

6.10 Questions:

- Is the appropriate way to handle subregional organizations?
- How are unique issues like Northwest hydro considerations to be folded in?
- Some feel the Board should not determine if a subregional RTG is acceptable. If a subregional RTG meets FERC criteria and is recognized by FERC, should be accepted.

9.1 At line 10: ". . . (iii) support the Association's interface ~~with WSCC, other~~ industry organizations and Subregional Coordination Groups. To carry out these responsibilities, the Planning Committee~~, in conjunction with WSCC,~~ shall:"

Other Issues

2.17 At line3: ". . . reasonable reliability requirements ~~as determined by the reliability criteria of such Member and~~ consistent with Prudent Utility Practice and regional reliability criteria, which requirements shall be impartially applied without ~~undue~~ discrimination. "

2.21 Question:

- How do you include the Canadian or Mexican participants under this definition?

3.3 Question:

- Should there be a specific section of duties when other duties, including the major commitment to provide transmission service is elsewhere (See 10.1)

3.3.1 Question:

- With regard to not requiring a Member to participate in a study exclusively of its own system initiated by another party, suggest adding ". . . unless in regard to a transmission request" or something to that effect.

5.2 At line 2: ". . . Members ~~shall~~ may select up to three directors . . ."

5.3 Question at line 6:

- Does the affiliation rule mean that an organization and its affiliate cannot hold separate memberships?

5.4 Questions:

- At line 8: What is meant by the language: ". . . for terms of three years and until a successor is elected . . ." ?
- At line 12: Should there be a balance on the initial board so that not all members of one class are replaced at the same time?

5.5 Question at line 5:

- Is the phrase ". . . other than from expiration of a term of office. . ." necessary?

5.7 Question:

How are regular meetings of the board convened -- in a previous meeting?

5.9 At line 11 "By providing ~~advance~~ written notice to ~~all other Directors~~ the Board, a Director may designate . . ."

6.5 Alternatives:

- At line 10, ". . . provided that only appointed Committee members . . ." At line 13, ". . . resolved by a majority vote of each voting class . . .", or
- Rather than have committees with restricted voting membership, make the committees open to participation by all members stay with simple majority voting."

6.9 Question at line 3:

- " . . . are employed by Members." Should this list be so restrictive and eliminate outside, qualified experts?

8. Alternatives:

- 8.1.2, at line 2: " . . . based upon ~~total~~ revenues from the wholesale purchase and sale of electricity in the Western Interconnection." or
- 8.1, "The administrative costs of the Association shall be capped at $xxx,xxx annually and shall be allocated as follows:"
  8.1.2, at line 2: " . . . sale of electricity in the Western Interconnection."

10.1 At line 6: ". . . on a basis consistent with its obligations under the FPA and the FERC's applicable standards . . ."

At line 15: " . . . ~~nonetheless~~ agree . . ."

10.3 Questions:

- At line 1: Does waiver of §211 compromise the workability of the appeal process?
- At line 8: Need to review of FERC "Policy Statement Regarding Good Faith Requests for Transmission Service" to verify if Bylaws are consistent.

10.4.2 At line 15: "Such study shall be completed within a reasonable time period, in accordance with the FERC's then current policies, as agreed by the Transmission Provider and Transmission user, or if such Members cannot agree, as determined by the Planning Committee."

Questions:

- Concern has been expressed that the time frames implied for studies in 10.4.1 are clearly implied in 10.4.2.
- Why involve the Planning Committee in the role of arbitrator?
- Are their similar requirements elsewhere in the Bylaws which should be altered to clarify the Planning Committee's role?
- At line 4: Concerning the language ". . . conduct a study . . . at the Transmission User's expense . . .", should this always hold? The Transmission Provider may also benefit from the study.

11. At line 5: ". . . in a manner consistent with its obligations under the FPA and the applicable then-established standards . . ."

Question at line 8:

- Is the language for non-US participants adequate?

12.1.1 Alternatives:

- At line 14: "A resolution may ~~consist of~~ include referring the matter to ~~another body~~ a technical body (e.g., the WSCC Technical Advisory Panel) for resolution or an advisory opinion." **or**
- At line 14: "A ~~resolution~~ facilitator may ~~consist of~~ refer~~ring~~ the matter . ."

12.1.2 At line 4: ". . . ~~such~~ either Member~~s shall be deemed to be at impasse and~~ can commence the binding arbitration process."

Question at line 2:

- Should the arbitration be triggered at 30 days even if the parties agree to continue with the facilitator?

12.1.3 At line 2: ". . . performance under treaties or of executed agreements ~~or service schedules~~ that have been approved . . . "

12.2.3 At line 8: " . . . of a disputing ~~Transmitting Utility Member's~~ Transmission Provider's reliability criteria; provided, that the Transmission Provider's reliability criteria, standards, guidelines, and operating procedures, which are ~~based upon regional reliability council criteria~~ in effect as of January 1, 1994, shall be afforded a rebuttable presumption . . . "

12.2.4 At line 3: " . . . and may request additional information including the opinion of a WSCC Technical Advisory Panel or other recognized technical experts."

At line 8: "Other ~~interested Members~~ affected parties may request . . ."

Question at line 8:

- Should there be a formal process for intervention in a dispute?

12.3 Questions:

- At line 1: Does the arbitration need a safety valve, such as rejecting both proposals and asking for new ones if the original proposals are found to be illegal, not in accordance with FERC policy, etc.
- At line 4: How do you handle the standard for non-US members? One suggestion might be ". . . which best meets the terms and intent of these Bylaws and conforms with the FPA and FERC's standards and policies, or is no less favorable that such statute, standards and policies when the Transmission Provider is not subject to §211 of the FPA."?
- At line 9: Why isn't the decision of an arbitrator to be precedent to other disputes? (see related question regarding 12.5 at line 14)
- Is language needed to avoid having an arbitrator from making specific cost of service decisions, such as for rate of return?

12.4 Question:

- How is an award to be enforced with a recalcitrant party? FERC? Federal Courts?

12.5 Questions:

- How are appeals to be handled where non-US participants are involved? It is suggested that a separate section be added to handle such appeals to an arbitration panel. How would such a panel be formed? Is their some other body which might serve?
- At line 1: There needs to be clarification to indicate that the Transmission User must submit the dispute to the FERC at the request of any party to the dispute in order to trigger a §211 proceeding.

- At line 6: Disagreement exists over whether the FERC ought to be allowed to not hear the appeal, in particular, whether no judicial review can be obtained of a decision of FERC not to take a case.
- At line 14: Why is arbitrator's decision not to be given deference? (see related question regarding 12.3 at line 9)

12.6 Comments:

- Concern has been expressed that this section is not fully consistent with the preceding section on the obligation of the User to make a §211 filing.
- At line 9: Section 12.5 says FERC silence for 90 days is equivalent to accepting the appeal, but this section stays only if order issued to accept appeal. In general what is the process to be to obtain a stay since the appeal will be under §211.

14. Add, break-up and change as follows:

14.1 General Reservation of Substantive Rights. These Bylaws specify procedural requirements only and do not constitute a requirement or consent by any Member to any substantive terms or conditions of public utility service. No Member waives any right that it would otherwise have, had it not joined the Association but instead proceeded to FERC directly or was the respondent in a FERC proceeding. All Members are specifically presumed to have preserved their rights under Sections 205, 206, and 306 of the FPA to file for rate changes or rate methodology changes or to request rate reductions or investigations of rates and charges; and all Members are specifically presumed to have preserved their rights to assert to both the arbitrator and to FERC on appeal that a proposed transaction is not expressly permitted by Section 212 of the FPA and that as a result the transaction does not meet the public interest standard in Section 211 of the FPA.

14.2 These Bylaws shall not, in and of themselves, be construed as a tariff, rate schedule or service agreement providing for transmission service.

14.3 These Bylaws shall not be construed as an agreement of any Member to provide transmission services of a type ~~of~~ or under circumstances that would not be required by the FERC pursuant to FPA Section 211 or 212. ~~Nothing in these Bylaws shall be construed as affecting the right of a Member to unilaterally make application to FERC for a change in rates or rate methodologies under Sections 205, 206, and 306 of the FPA.~~

14.4 No Impact on Contracts or Other Legal Obligations. These Bylaws do not replace, modify, supersede or limit any contract, decision of regulatory agencies or courts of law, or other legally enforceable entitlement or rights of any Member except as specifically provided herein.

15. At line 2: ". . . amended under the voting procedure of Subparagraph 4.3 at any annual or special meeting of the Members."

16.1 At line 1: "~~Subject to any applicable state and federal law which may specifically limit a Member's ability to enter into this Section, n~~No Member, its directors. . . "

CALIFORNIA MUNICIPAL UTILITIES ASSOCIATION

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JERRY JORDAN, Executive Director

September 30, 1993

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Re: WATSCO BYLAWS

Dear Mr. Larson:

Roger Fontes of NCPA asked that I respond to a request from Jim Byrne to provide you with an "...up-to-date copy of the WATSCO bylaws and a short report on the status..." of WATSCO discussions. I am enclosing a copy of the March 31, 1993 draft of the WATSCO Bylaws. This is the last negotiated version of the bylaws and was approved "in concept" by all municipal utilities that had been involved in the negotiations as well as representatives of Independent Energy Producers and the Geothermal Resources Association. To our surprise and disappointment, none of the investor-owned utilities were willing to sign a Memorandum of Understanding expressing the parties' conceptual approval. Since that time there have been no further negotiating sessions involving all of the parties to the WATSCO negotiations.

However, commencing in August, LADWP and SCE have held discussions in an attempt to resolve a list of outstanding issues. These talks are confined to these two parties in hopes that issues may be resolved more expeditiously when only two parties are involved. If LADWP and SCE are successful, they will circulate a set of proposed amendments to the March 31 draft among the remaining parties to the WATSCO negotiations. If these amendments are acceptable or nearly acceptable to a "critical mass" of the parties, then I would expect rapid and successful conclusion to WATSCO negotiations. If, on the other hand, LADWP and SCE are unable to reach agreement fairly soon, or if they reach an agreement that is not acceptable to most other parties, then we can probably lay WATSCO to rest.

As I am sure you are aware, discussions have begun on draft bylaws for a "Westwide" RTG. Many parties, including CMUA, are involved in these discussions, and at this point they hold out some promise of a workable outcome.

I hope this information is helpful in preparation for your RTG workshop. We wish you success. Please let us know if we can be of any other assistance.

Sincerely,

Stuart E. Wilson
Assistant Executive Director

enclosure

cc: Roger Fontes

3/31/93 (Final text subject to approval by all parties.)

BYLAWS

OF THE

WESTERN ASSOCIATION FOR

TRANSMISSION SYSTEMS COORDINATION

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Appendix B - Membership List

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[Additional appropriately drafted Exhibits will be attached when Members located in another state joins WATSCO.]

BYLAWS OF THE
WESTERN ASSOCIATION FOR TRANSMISSION SYSTEMS COORDINATION

1. **PREAMBLE:** These Bylaws of the Western Association for Transmission Systems Coordination ("WATSCO") are made with reference to the following facts among others:

1.1 **Scarcity of Electric Transmission Resources** - Electric transmission capacity is a scarce and valuable resource which is imbued with the public interest. Often, the construction of transmission facilities and the acquisition of transmission corridors utilize valuable public lands and/or involves the taking of valuable private property through the power of eminent domain by publicly or privately owned utilities. Use of this scarce resource should therefore be in a manner which promotes the broadest public benefit and should not be used to competitive advantage.

1.2 **Societal Benefits** - Efficient use of existing and future transmission facilities on a fair, non-discriminatory basis can yield many societal benefits that include:

- enhanced economic efficiency;
- increased competition in the electric power market;
- better protection of the environment;
- better use of public transmission corridors; and,
- lower electricity rates for all consumers.

These benefits can best be realized through a voluntary organization of electric utilities and non-utility generators.

1.3 **Purpose of WATSCO** - WATSCO is formed expressly for the purpose of facilitating the more efficient use of existing transmission facilities and coordinating the planning for expansion of the transmission system on a regional basis without impairing reliability and service to Native Load. Use of transmission facilities includes long-distance bulk transmission service, transmission service within and between control areas for wholesale utility customers and non-utility generators, and all other services available under Sections 211 and 212 of the Federal Power Act.

1.4 **Regional Transmission Planning** - Members recognize the need for region-wide coordinated planning of transmission facilities to assure the most efficient development and expansion of the transmission system to serve the needs of all consumers and power providers with a minimum of adverse environmental impacts. Coordinated transmission planning should be performed on a regional basis to meet the

transmission service needs of all Members. Coordinated planning will ensure the efficient use of existing transmission facilities, reducing the need for new transmission facilities, thereby minimizing environmental impacts. Such planning will assure the most efficient development and expansion of the transmission system.

1.5 **Transmission Capacity** - In order to ensure that adequate transmission capacity exists to meet all Members needs, Members must increase transmission capacity when necessary to accommodate transmission requests from other Members.

1.6 **Pricing Principles** - To the extent consistent with the FPA, FERC regulations and precedents and these Bylaws, the pricing of transmission services under these Bylaws shall be cost-based and shall not be at the expense of the customers or owner of the Member providing such services.

1.7 **Membership** - To maximize the effectiveness of WATSCO, membership in WATSCO will be open to any entity generating electric energy for sale for resale as defined in Section 211 of the Federal Power Act and all publicly owned and investor owned electric utilities, rural electric cooperatives, federal power marketing agencies, state agencies owning or planning transmission or generation, joint powers agencies of electric utilities, non-utility generators and other transmission owners.

2. **AGREEMENT:** In consideration of the premises and mutual covenants and agreements herein, the parties hereto agree as set forth herein.

3. **DEFINITIONS:** The following capitalized terms, whether in the singular or the plural (unless specifically provided otherwise), when used in the text of these Bylaws shall have the following meanings:

3.1 **Available Transmission Capacity** - That amount of transmission capacity on the appropriate and/or affected portion of a Member's transmission system (including entitlements) which is not needed to accommodate:

(i) The Member's existing and Planned Native Load requirements;

(ii) Existing commitments for Firm Transmission Service contracts including those with full or partial requirements transmission customers;

(iii) The existing and Planned Native Load requirements of all Members located within the Member's control area to the extent that these Members are or will be dependent upon said Member for transmission service consistent with control area operator's contractual and/or regulatory obligation to do so, and to the extent not included in Section 3.1(i) and (ii) above;

(iv) Transmission capacity which is temporarily committed for a competitive resource acquisition process as provided in the applicable Appendix A, until such process has progressed to a stage where it is reasonably certain that such capacity will not be utilized with respect to the subject resource acquisition; and

(iv) Prudent Reserve.

As used in this Section 3.1, "Planned Native Load requirements" shall include only such transmission capacity (i) specified by duration of service, transfer capability required, the point of receipt and the point of delivery, and (ii) included in the transmission plans required in Section 4.7.

Notwithstanding the provisions of this Section 3.1, transmission capacity providing Firm Transmission Service shall be deemed Available Transmission Capacity with respect to requests for Interruptible Transmission Service under these Bylaws; provided, however, no Interruptible Transmission Service may displace Firm Transmission Service except upon mutual agreement of the Transmission Provider and the Transmission Requester.

3.2 **Board of Directors or Board** - The Board of Directors established pursuant to Section 8 of these Bylaws.

3.3 **CIAC** - Capital contributions in aid of construction with respect to Incremental Additions.

3.4 **Dispute Resolution Procedure** - The procedures set forth in Section 5.4 and Section 10 of these Bylaws for resolving disputes between and among Members.

3.5 **Dispute Resolution Proceeding or Dispute Resolution Process** - An application of the Dispute Resolution Procedure to a particular dispute between or among Members.

3.6 **FERC** - The Federal Energy Regulatory Commission.

3.7 **Firm Transmission Service** - Transmission service that is subject to interruption only for forced outages, unusual system operating conditions, scheduled maintenance or system jeopardies.

3.8 **FPA** - The Federal Power Act.

3.9 **Incremental Additions** - Additions, improvements or capital betterments (including interconnection facilities) to a Member's/Members' electric transmission system reasonably required for the purpose of increasing transmission capacity to accommodate a transmission service request of another Member.

3.10 **Interruptible Transmission Service** - Transmission service that is subject to the interruption by the Transmission Provider with or without prior notice for any reason whatsoever at the Transmission Provider's sole and absolute discretion.

3.11 **Long Term Transmission Plan** - Each State's transmission plan as specified in the applicable Exhibit A attached to these Bylaws.

3.12 **Member** - An entity which has executed these Bylaws and identified as such in Appendix B hereto.

3.13 **Native Load** - As of the first day of the most recent biennial planning cycle, the maximum instantaneous peak electrical load including operating reserves of a utility's retail customers, full requirements wholesale power customers, and partial requirements wholesale power customers to the extent of the electrical load supplied by such utility to such customers.

3.14 **Ownership-Like Rights** - The rights, benefits and obligations associated with ownership of specified transfer capability resulting from Incremental Additions including, but not limited to, the right to use, assign, sell or otherwise dispose of such transfer capability and the financial obligation to pay for any operation, maintenance or replacement costs authorized with respect to such Incremental Additions, but excluding (i) legal title and (ii) risks of downrating and the benefits of an uprating of such transfer capability.

3.15 Planned Native Load - Those Native Load requirements included in the transmission plans required in Section 4.7.

3.16 Planning Committee - The Planning Committee established pursuant to Section 9.

3.17 Prudent Reserve- An amount of transmission capacity set aside for one or more of the following:

(i) A utility's reasonable reliability requirements consistent with Prudent Utility Practice; and

(ii) Inadvertent flows and loop flow.

3.18 Prudent Utility Practice - Those standards (including current published reliability criteria, standards and guidelines of the Western Systems Coordinating Council and the North American Electric Reliability Council), practices, methods and equipment that are currently and commonly used by the electric utilities to plan, engineer, select, operate, schedule and maintain electric power facilities and equipment reliably and efficiently to serve their customers dependably and economically with due regard for the conservation of natural resources, protection of the environment and the state of the art in the electric power industry as applied in the WSCC area.

3.19 Radial Transmission Facilities - Facilities which:

(i) Are physically separated from the Transmission Provider's primary service area; or

(ii) Extend considerably beyond the Transmission Provider's high density service area; or

(iii) Comprise a specified contract path pursuant to existing contracts; or

(iv) Are functionally separate from the Transmission Provider's integrated network such that the facilities are, or can be, operated and planned as a single facility; or

(v) Carry power flows that can be identified and allocated for purposes of cost allocation.

3.20 Regulatory Authority - Any state regulatory authority or local governing board acting as a regulatory body, and

any federal regulatory body, including FERC, with jurisdiction over a decision, resolution or action arising in connection with these Bylaws.

3.21 **Transmission Provider** - Any Member possessing a right to transmission capacity either through ownership or contractual arrangements.

3.22 **Transmission Requester** - Any Member or Members requesting transmission service from a Transmission Provider pursuant to Section 5 and the applicable Appendix A.

3.23 **Type 1 Transaction** - Any transaction between or among Members in which the Transmission Provider is subject to FPA Sections 205 and 206.

3.24 **Type 2 Transaction** - Any transaction between or among Members in which the Transmission Provider is not subject to FPA Sections 205 and 206.

3.25 **Uncontrollable Force** - Any cause beyond the control of the Member affected, including, but not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, pestilence, lightning or other natural catastrophes, epidemic, famine, war, riot, civil disturbance or disobedience, labor dispute, strike, labor or material shortage, sabotage, government priorities, restraint by court order or public authority, and action or non-action by or inability to obtain necessary authorizations or approvals from any governmental agency or authority which, by exercise of Prudent Utility Practice, due diligence and foresight, such Member could not reasonably have been expected to avoid and which, by exercise of due diligence, it has been unable to overcome.

3.26 **WSCC** - The Western Systems Coordinating Council.

4. COORDINATED TRANSMISSION PLANNING:

4.1 **Purpose of Coordinated Transmission Planning.** Each Member shall provide information requested by the Planning Committee to facilitate coordinated transmission planning which will emphasize: reliability planning; the efficient use and operation of transmission systems; and the construction of new facilities or reinforcements to existing transmission systems in order to accommodate existing and planned transmission needs. For the purpose of establishing a clear understanding of the operating capabilities and constraints of the transmission system, each Member shall provide to the Plann

Committee verifiable information about such Member's (i) existing and planned electric system and transmission entitlements and (ii) transmission needs.

4.2 **Planning Criteria.** With respect to all planning activities under these Bylaws, the following criteria shall govern:

4.2.1 Applicable Reliability Criteria - The applicable reliability criteria and guidelines of the North American Electric Reliability Council and WSCC, and each individual Member's reliability criteria shall govern the planning, design and operation of such Member's system. Each Member utility's reliability criteria shall be consistent with Prudent Utility Practice and shall be consistently applied regarding a Transmission Provider's expected use of its system and similar requested use of such system by a Transmission Requester.

4.2.2 WATSCO Planning Criteria - Such other planning criteria as developed by the Planning Committee and approved by the Board.

4.3 **New Projects.** Each Member acknowledges that new transmission projects and generation resources will affect existing transmission systems. New transmission projects shall conform with minimum acceptable reliability criteria as set forth in Section 4.2 and shall not reduce pre-existing transfer capability at points of interconnection between Members' systems except by mutual agreement among affected Members. In any Dispute Resolution Proceeding in which it is asserted that the new project fails to conform to the control area Member's minimum acceptable reliability criteria, the burden of proof with respect to such conformance shall be on the Transmission Requester.

4.4 **Parallel Path Flows.** Each Member recognizes that in the operation of an integrated electric transmission system, parallel path flows will occur and may be beneficial or detrimental to the overall operation of a Member's system. Coordinated planning under these Bylaws shall take into account parallel path flows in the design of new projects and the provision of new services so as to mitigate, consistent with Prudent Utility Practice, the detrimental effects of parallel path flows on each Member's system and utility systems interconnected thereto.

4.5 **Repository for Planning Information.** The Planning Committee shall establish or designate a repository, including all operating and procedural matters related thereto, for all planning information obtained through these Bylaws which shall be

accessible to all Members. The Planning Committee will coordinate system data requirements in order to help Members identify Available Transmission Capacity.

4.6 Member Requests for Information from other Members; Costs of Requests; Confidential Information; Restricted Software.

4.6.1 Request for Information from other Members. If a Member desires information which is unavailable in the data repository established pursuant to Section 4.5, such Member may request from any other Member, and such other Member shall provide within a reasonable period of time from receipt of the request, electrical system data and representations for the specified portion of its transmission facilities and any other information about its system requested by such Member in order to permit such Member to: (i) assess Available Transmission Capacity; (ii) assess the need for, and system performance associated with, new transmission facilities, to the degree not represented in the repository; or (iii) make any other assessment pertinent to these Bylaws.

4.6.2 Costs of Request Paid by Requesting Member. The Memb requesting such data and information is obligated pay the other Member's reasonable costs for providin the requested data and information.

4.6.3 Data Treated as Confidential. Any data or information received from another Member shall be treated as confidential by all Members which obtain or receive such data or information and shall not be distributed to a non-Member without the previous consent of the Member providing such data or information. Each Member receiving such information shall protect the confidentiality of such information in any proceeding before a court or regulatory body. If a third party asserts a legal right to disclosure of confidential information, the Member against which disclosure is sought shall notify the Member who designated the information confidential as soon as reasonably possible following the request so that such Member may assert any legal privileges, rights, obligations or defenses.

4.6.4 Data Subject to Restrictions. To the extent requested data or information is unavailable or limited due to licensing restrictions, the Member using such restricted software, hardware or models shall requ the licensing company to remove or conditionally remo

such restrictions, and at a minimum, the Member shall provide to the requesting Member the study results from such restricted software, hardware, or models. The requesting Member shall bear the reasonable cost imposed by the licensing company of removing or conditionally removing such restrictions to allow the use of such restricted software, hardware or models by such requesting Member under these Bylaws. Notwithstanding the foregoing, a Member may not withhold proprietary information or computer software, hardware or models that is deemed relevant by an arbitration panel in a Dispute Resolution Proceeding, provided that appropriate measures shall be taken to maintain the confidentiality of such proprietary material in the Dispute Resolution Proceeding at the reasonable cost of the requesting Member.

4.7 Initial and Biennial Information. Except as otherwise determined by the Planning Committee, each Member shall provide the following information within 6 months (or such other time frame as determined by the Planning Committee) of executing these Bylaws and thereafter at the beginning of each biennial planning cycle (as specified by the Planning Committee). The following information shall be provided in the format specified by WSCC or, absent such format, by the Planning Committee.

4.7.1 Transmission System Data and Representation. Each Member that operates a control area shall, for the current year summer peak and other applicable system constrained conditions, provide generation and transmission system data and system representations of all existing transmission facilities within its control area operated above 100 kV. Such data and representations shall, to the extent feasible, be consistent with those prepared for planning studies of the appropriate regional reliability council. Each Member shall cooperate with the control area operator in fulfilling the requirements of this Section. The Planning Committee shall determine the type of data and representations to be submitted by each Member which may include a description of all components of the transmission facilities represented by such data, including the length, size, electrical characteristics and rating of transmission line segments; capacitor, circuit breaker, bus and/or transformer ratings (including emergency ratings if used in the design of the system); and other system elements to the extent such elements may limit transfer capability.

4.7.2 Planning Criteria. Each Member, when supplying transmission system data, shall also supply the transmission design, operating, and reliability criteria currently used in the planning of its system.

4.7.3 Intertie Data. Each Member shall provide information specifying the transfer capability of each of its interties with other utility transmission systems and a summary of its contractual obligations to provide service, the amount of Firm Transmission Service, and other firm-type uses/commitments by such Member which affect these interties.

4.7.4 Information on Planned Transmission Facilities. Each Member shall provide its Long Term Transmission Plan, as specified in the applicable Exhibit A regarding Long Term Transmission Plans and as required in Section 4.8, for new transmission facilities and reinforcements over 100 kV and additional, associated interconnection facilities. The plan shall include a description of each transmission project including a single line diagram, the project's functional purpose and design specifications (if available), the expected operating date, data required to incorporate the project in utility's transmission representation and, for upgrades to system interconnections, the expected increase in transfer capability. Information on specific transmission projects less than 100 kV shall be provided as requested by the Planning Committee to facilitate coordinated planning. Each Long Term Transmission Plan shall include the following information, including any underlying assumptions and supporting data or analysis and any other information required in the applicable Exhibit A for Long Term Transmission Plans, for the applicable planning period:

(i) Existing and planned control area generation to meet the needs of Native Load;

(ii) Firm intertie ratings;

(iii) Existing and planned firm imports to meet the needs of Native Load;

(iv) Existing and planned firm exports;

(v) Existing commitments for transmission services;

(vi) Reservation for Prudent Reserve;

(vii) Available Transmission Capacity;

(viii) New transmission facilities over 100 kV and additional interconnection facilities;

(ix) If available, estimates of the cost of each planned reinforcement, including the proposed allocation of such costs to the forecast transmission users;

(x) Current and expected uses of existing transmission facilities including accommodation of economy transactions;

(xi) The location, duration and quantity of Available Transmission Capacity;

(xii) The location, duration and quantity of all pending transmission service requests;

(xiii) The location of transmission constraints;

(xiv) Current plans for the Member's transmission system, transmission entitlements, and resource additions and modifications;

(xv) Identification of computer data bases and assumptions used for modeling the Member's existing and planned electrical systems;

(xvi) Any information required to satisfy FERC with respect to Section 213 of the FPA regarding potential transmission capacity and known constraints; and

(xvi) Explanation of how the above were developed.

4.7.5 Planned Resource Development. The Long Term Transmission Plans produced in the coordinated planning process can be accurate only to the extent that the resource plans reflected in the plans are accurate. Each utility Member is required, and each non-utility Member is encouraged, to provide to the Planning Committee its generation development plans and the requirements for transmission necessary to implement these plans. Such plans and requirements shall promptly be provided to the Planning Committee by a non-utility Member following such non-utility Member's execution of a power sales agreement with respect to any power resource.

4.7.6 Proprietary Information. To the extent practicable, a Member shall use computer software, hardware or models without licensing restrictions that prohibit or limit the submission of data or information required under these Bylaws. Any Member that uses proprietary information or computer software, hardware or models with such prohibitive licensing restrictions shall advise the Planning Committee at the time that the Member withholds or partially discloses any data or information required under these Bylaws.

4.7.7 Additional Information. The Planning Committee may require Members to provide any additional information at times and in a form deemed necessary to accomplish the goals of coordinated transmission planning.

4.8 Coordinated Planning Process. Each Member that owns or plans to construct or acquire transmission facilities, or is otherwise entitled to transmission capacity, will biennially prepare a Long Term Transmission Plan and provide that Plan to the Planning Committee as part of the coordinated planning process. With respect to such Members, the process of preparing such Long Term Transmission Plan will consist of the following activities undertaken at times specified by the Planning Committee in the following order:

4.8.1 Long Term Transmission Plan - Each such Member shall provide to the Planning Committee data as described in Section 4.7 on such Member's need for transmission capacity over the period of time specified in the Exhibit A regarding Long Term Transmission Plans applicable to such Member, including any plans for additional resources or new and upgraded transmission facilities.

4.8.2 Provide Assumptions and Data - Each such Member shall provide to the Planning Committee the assumptions, criteria and data that will be used in preparation of its Long Term Transmission Plan.

4.8.3 Draft Long Term Transmission Plan - Each such Member shall prepare a draft Long Term Transmission Plan to serve all its forecasted transmission needs over the period of time specified in the Exhibit A regarding Long Term Transmission Plans applicable to such Member.

4.8.4 Review and Comment - The Planning Committee shall distribute to each Member all Long Term Transmission Plans for review and comment.

4.8.5 Final Long Term Transmission Plan - Each such Member shall prepare and distribute to the Planning Committee a final Long Term Transmission Plan which takes into consideration the comments received.

4.8.6 Cooperation - Each Member shall cooperate with the Planning Committee in preparing the plans pursuant to this Section 4.8.

5. TRANSMISSION SERVICE UNDER THESE BYLAWS:

5.1 **Request for Transmission Service.** A Transmission Requester shall request transmission service from a Transmission Provider in writing as provided in the applicable Appendix A and, to the extent not otherwise provided therein, in a form established by the Planning Committee. Such form of request shall include, but not be limited to, (i) a statement that the request for transmission service is a "WATSCO request", (ii) the amount of transmission capacity requested, (iii) the nature and duration of the requested transmission service, and (iv) the points of origin, receipt and delivery. The transmission request initiates the process of evaluating the request, conducting the necessary studies by the Transmission Provider, and ultimately providing the requested service pursuant to the provisions of these Bylaws. This process is set forth in Appendix A hereto, "Transmission Service Requests". An Appendix A shall be prepared and attached to these Bylaws with respect to each State in which a Member is located.

5.1.1 Commitments for Planned Transmission Service. Whenever a Member submits a request for transmission service pursuant to this Section 5 and the applicable Appendix A which competes with or is affected by another Member's specific planned need for transmission services set forth in its transmission plan pursuant to Section 4.7, the Member that has planned for the specific service (the "planning Member") shall have the first right to the specific service if, and only if, the planning Member commits to such specific service pursuant to Section 5.1.2.

5.1.2 Commitments by Non-Transmission-Owner Members. Where the planning Member does not own the transmission system that would be used for the specific planned service, the commitment required by Section 5.1.1 shall consist of a contract for transmission service (in accordance with these Bylaws) between the planning Member and the Member which owns the subject transmission system. The

planning Member shall submit a request pursuant to Section 5 and the applicable Appendix A for such contract no later than 30 days following the submittal of the competing request. The contract between the planning Member and the owner of the subject transmission system shall be executed no later than 180 days (or such longer period of time as agreed to by the Requesting Member) from the date of the competing request.

5.2 **Transmission Service Using Available Transmission Capacity.** A Transmission Provider shall offer transmission service utilizing Available Transmission Capacity to any Transmission Requester pursuant to this Section 5 and the applicable Appendix A. The position of any Member that transmission capacity is not available pursuant to Sections 3.1(i) through 3.1(v) may be challenged by any other Member and fully reviewed in any Dispute Resolution Proceeding. For purposes of determining Planned Native Load, forecasts of service area demand adopted following a public hearing by a state's energy planning agency and any assumptions ordered by a regulatory agency shall be conclusively presumed correct in any such Dispute Resolution Proceeding. Any assumption which does not have the force of law shall not be determinative, nor shall it create any presumption, regarding any Member's future need for transmission capacity or whether such capacity is Available Transmission Capacity pursuant to Section 3.1. If, following the process of requesting transmission service pursuant to the applicable Appendix A and this Section 5 transmission service is to be provided using Available Transmission Capacity, rates and other terms and conditions of such transmission service shall be determined in accordance with Section 5.4 through Section 5.9.

5.3 **Transmission Service Requiring Incremental Additions.**

5.3.1 Transmission Provider Obligation to Acquire and Construct Incremental Additions. If following the process of requesting transmission service pursuant to the applicable Appendix A, in order to provide the requested transmission service, it is determined that Incremental Additions will be required to provide the requested transmission service, the Transmission Provider shall be obligated to acquire and construct sufficient Incremental Additions to provide such transmission service, subject to obtaining all necessary property rights and applicable Federal, state and local permits and approvals. The Transmission Requester shall fully

support at its expense the need for such Incremental Additions before any court, regulatory authority or governing body which is empowered to grant any such property right, permit or approval. If, after undertaking and carrying out good faith efforts, the Transmission Provider shall be unable to obtain such property rights, permits and approvals or is prevented from acquiring and constructing such Incremental Additions due to a determination of a court or regulatory agency having proper jurisdiction, its obligation to acquire and construct such Incremental Additions shall be discharged with respect to such transmission request. However, if the Transmission Provider is denied regulatory approval to include such Incremental Addition in its rate base, the Transmission Requester may provide CIAC with respect to such Incremental Addition. In such event, the Transmission Provider shall continue to be obligated to acquire and construct such Incremental Additions subject to obtaining all necessary property rights and other applicable Federal, state and local permits and approvals.

5.3.2 Financing of Incremental Additions Not in Transmission Plans. If pursuant to the applicable Appendix A and this Section 5 a transmission service request will result in the acquisition and construction of Incremental Additions which are not included in the Transmission Provider's Long Term Transmission Plan consistent with its demonstrable forecast of Planned Native Load requirements:

5.3.2.1 The Transmission Provider shall determine, in its sole discretion, whether Incremental Additions, where they constitute new Radial Transmission Facilities which do not intertie or interconnect two or more electrical control areas, will be financed (i) by the Transmission Provider, or (ii) utilizing CIAC from the Transmission Requester; or

5.3.2.2 The Transmission Requester shall determine, in its sole discretion, whether such Incremental Additions, where they constitute new Radial Transmission Facilities which intertie or interconnect two or more electrical control areas, will be financed (i) utilizing CIAC from the Transmission Requester or (ii) as

determined by the Transmission Provide. pursuant to Section 5.3.2.1.

5.3.3 Financing Incremental Additions Through CIAC - Ownership or Ownership-Like Rights. If Incremental Additions are to be financed utilizing CIAC as provided in Section 5.3.2, the Transmission Requester providing CIAC shall acquire (i) Ownership-Like Rights to all specified transfer capability resulting from such Incremental Additions which are not new Radial Transmission Facilities, or (ii) ownership rights to all such Incremental Additions which are new Radial Transmission Facilities, except as otherwise agreed upon by the Transmission Requester and the Transmission Provider. Ownership-Like Rights by the Transmission Requester in such Incremental Additions shall result in the Transmission Provider making the specified transfer capability available to the Transmission Requester so long as such Transmission Requester pays for (a) the operation, maintenance and replacement costs of such Incremental Additions and (b) any increased operation or maintenance costs on the Transmission Provider's system which are direct result of the operation of such Increment. Additions.

5.3.4 Firm Level of Service for Incremental Additions other than New Radial Transmission Facilities. In addition to other terms and conditions regarding transmission service provided with respect to Incremental Additions which are not new Radial Transmission Facilities and are financed through CIAC by a Transmission Requester, the transmission service contract shall specify the amount, and terms and conditions, of transmission service to be provided by the Transmission Provider. The Transmission Provider shall provide Firm Transmission Service in the amount specified in accordance with Section 5.3.3. Except as otherwise agreed to by the Transmission Provider and the Transmission Requester, there shall be no adjustment in such specified level of Firm Transmission Service in the event an increase or decrease in the rating of such Incremental Additions or the resulting transfer capability shall occur during the period in which service is to be provided to such Transmission Requester in connection with such Incremental Additions; i.e., the risks of a downrating and t benefits of an uprating of the Increment.

Facilities or the resulting transfer capability shall remain with the Transmission Provider.

5.3.5 Incremental Additions in Transmission Plans. In cases where the Incremental Addition is included in the Transmission Provider's Long Term Transmission Plan consistent with the demonstrable forecast of Planned Native Load requirements and the construction of the Incremental Additions is accelerated in order to provide requested transmission service, transmission service under the terms of these Bylaws shall be made available to a Transmission Requester, pursuant to Section 5 and the applicable Appendix A, until such time as the capacity of such Incremental Additions is needed pursuant to such Long Term Transmission Plan consistent with the demonstrable forecast of Planned Native Load requirements or such other date as mutually agreed to by the Transmission Provider and the Transmission Requester; provided that the Transmission Requester pays the costs associated with the acceleration of the construction of the Incremental Additions through rates or advances of CIAC sufficient for the accelerated acquisition and construction of the Incremental Additions.

To the extent permitted by then current FERC policies, if CIAC is advanced by a Transmission Requester, then the Transmission Provider shall repay a proportionate amount of CIAC at such time as the Incremental Addition is required by the Transmission Provider pursuant to its Long Term Transmission Plan consistent with its demonstrable forecast of Planned Native Load requirements or such other date as mutually agreed to by the Transmission Provider and the Transmission Requester. Notwithstanding the temporary use of such Incremental Addition to provide transmission service to such Transmission Requester, the Transmission Provider shall continue to be obligated to build Incremental Additions to meet the transmission requests of such Transmission Requester pursuant to this Section 5 and the applicable Appendix A without interruption of transmission service.

5.3.6 Commercially Reasonable Assurances Regarding Payment of Costs Incurred for Incremental Additions. A Transmission Requester shall provide to the Transmission Provider commercially reasonable assurances regarding the payment of construction

costs incurred by a Transmission Provider with respect to the design, acquisition and construction of Incremental Additions.

5.3.7 Costs of Incremental Additions Reduced by Amount of Benefits to Transmission Provider's Electrical System. The costs of Incremental Additions paid by a Transmission Requester shall be reduced by the amount of benefits to the transmission system of the electrical system providing the transmission service.

5.3.8 Operation and Maintenance of Incremental Additions. Incremental Additions on a Transmission Provider's system, including new Radial Transmission Facilities, shall be operated and maintained by such Transmission Provider.

5.4 Determination of Pricing and Other Terms and Conditions of Transmission Service. To the extent consistent with the FPA, FERC regulations and precedents and these Bylaws, the pricing of transmission services under these Bylaws shall be cost-based and shall not be at the expense of the customers or owners of the Member providing such services.

5.4.1 Negotiate Rates, Terms and Conditions. If following the process of requesting transmission service pursuant to this Section 5 and the applicable Appendix A hereto, transmission service shall be provided to a Transmission Requester, then the Transmission Provider and the Transmission Requester shall, in the first instance, negotiate the rates (including the methodology and rate design used to calculate the rates) and other terms and conditions of the transmission service to be provided.

5.4.2 Agreement on Rates, Terms and Conditions. If the Transmission Provider and the Transmission Requester agree upon the rate, rate methodology/design and other terms and conditions of service:

5.4.2.1 With respect to a Type 1 Transaction, the Transmission Provider shall (i) execute and deliver a contract to set forth and implement the agreed upon rate, rate methodology/design and other terms and conditions of service, and (ii) file with FERC a tariff or tariff amendment consisting of such rate, rate methodology/design and other terms

conditions of service as provided in Subpart B of Part 35 of Title 18, C.F.R. Both the Transmission Provider and the Transmission Requester shall fully support such filing before FERC; or

5.4.2.2 With respect to a Type 2 Transaction, the Transmission Provider and the Transmission Requester shall execute and deliver a contract to set forth and implement the agreed upon rate, rate methodology/design, and other terms and conditions of service.

5.4.3 Failure to Agree - Initiate Dispute Resolution Procedure. If any rate, rate methodology/design, or any other term or condition is not agreed to by the Transmission Provider and the Transmission Requester within the appropriate time period as provided in Section I of the applicable Appendix A (or such longer period as is agreed to by the Transmission Requester and the Transmission Provider) the Transmission Provider and the Transmission Requester shall mutually prepare a list of the rate, rate methodology/design, or other terms and conditions which have been agreed to and a list of such terms and conditions which are unresolved. Within ten (10) days after the preparation of such lists, the Transmission Provider shall submit such list of unresolved terms and conditions to a Dispute Resolution Proceeding. In such Dispute Resolution Proceeding, the Transmission Provider and the Transmission Requester shall stipulate to such list of terms and conditions which have been agreed upon.

5.4.3.1 Requester or Provider May Contest in Dispute Resolution Proceeding. The Transmission Requester and/or the Transmission Provider may contest on the merits the matters submitted to a Dispute Resolution Proceeding pursuant to Section 5.4.3 in accordance with the Dispute Resolution Procedure.

5.4.3.2 Written Award in Dispute Resolution Proceeding. The Dispute Resolution Procedure panel shall render a written award regarding the matters submitted for decision pursuant to Section 5.4.3. Such award shall be rendered:

(i) With respect to a Type 1 Transaction, to produce a result which is within the range of

results which could apply if FERC were making the award at that time, on the same matters, and in accordance with applicable provisions of the FPA, applicable FERC regulations and precedents, and these Bylaws, in each case as then in effect; or

(ii) With respect to a Type 2 Transaction, to produce a result which is within the range of results which could apply if FERC were making the award at that time, on the same matters, and in accordance with Sections 211 and 212 of the FPA, applicable FERC regulations and decisions, and these Bylaws, in each case as then in effect.

5.4.4 File Tariff with FERC or Execute Contract. Subject to Section 5.4.5:

5.4.4.1 Promptly following an award in a Dispute Resolution Proceeding pursuant to Section 5.4.3.2(i), the Transmission Provider and the Transmission Requester shall execute and deliver a contract setting forth the terms of the award and the list of terms and conditions stipulated pursuant to Section 5.4.3. The Transmission Provider shall file with FERC a rate schedule, tariff or tariff amendment which consists of the rate, rate methodology/design and other terms and conditions to implement (i) the award and (ii) the list of terms and conditions stipulated pursuant to Section 5.4.3. Subject to Section 5.4.5, the Transmission Provider and the Transmission Requester shall both fully support such filing; or

5.4.4.2 Promptly following an award pursuant to Section 5.4.3.2(ii), the Transmission Provider and the Transmission Requester shall execute and deliver a contract to set forth and implement the rate, rate methodology/design and terms and conditions (i) set forth in the award and (ii) list of terms and conditions stipulated pursuant to Section 5.4.3.

5.4.5 Limited Appeal to FERC. The Transmission Provider and/or the Transmission Requester may appeal to FERC any award rendered pursuant to Sections 5.4.3 or 5.4.8 only upon the grounds that the award is

contrary to, or beyond the scope of, these Bylaws or is inconsistent with any then applicable FERC certification order with respect to these Bylaws, or is unjust, unreasonable, unduly discriminatory or preferential. [This standard of appeal is based upon the consensus language. This is acceptable if FERC adopts the provision in the consensus language indicating that awards in Dispute Resolution Proceedings will be "accorded substantial deference" by FERC.]

5.4.6 Failure to Provide List for Dispute Resolution Proceeding. If the Transmission Provider fails to submit the list of unresolved terms and conditions to a Dispute Resolution Proceeding in accordance with Section 5.4.3, the Transmission Requester may submit such list of unresolved terms and conditions to a Dispute Resolution Proceeding and the Transmission Provider and the Transmission Requester shall stipulate therein to the list of terms and conditions which have been agreed upon. If the Transmission Provider so fails to submit such list to a Dispute Resolution Proceeding, the Transmission Provider shall be deemed to have waived its right to submit such terms and conditions to a Dispute Resolution Proceeding but shall have the same rights to contest through the Dispute Resolution Procedure such unresolved terms and conditions as a Transmission Requester would have where the Transmission Provider submits unresolved matters to a Dispute Resolution Proceeding under Section 5.4.3.

5.4.7 Agree FERC-Jurisdictional Matter Fundamentally Different From FERC Policy. If the Transmission Provider and the Transmission Requester agree (each in its sole discretion) that the resolution of any matter subject to FERC jurisdiction submitted to a Dispute Resolution Proceeding is fundamentally different from any resolution of such a matter theretofore approved by FERC in a currently-applicable rule or precedential determination respecting the same or similar service, so that there are no usable standards to apply in rendering an award consistent with Section 5.4.3.2(i) or Section 5.4.3.2(ii), as the case may be, then:

5.4.7.1 The Transmission Provider and the Transmission Requester shall first resolve, by mutual agreement or in accordance with Section 5.4.3

(including any appeal pursuant to Section 5.4.5), all other terms and conditions which are not dependent upon the resolution of the matter described in Section 5.4.7 above; and

5.4.7.2 The Transmission Provider shall then file with FERC, within __ days after resolution of all terms and conditions pursuant to 5.4.7.1, a unilateral tariff or tariff amendment seeking authority to provide the requested service at such rates, terms and conditions as determined pursuant to Section 5.4.7.1 and the resolution of the matter described in Section 5.4.7, subject to refund, and calculated in accordance with applicable FERC regulations. The Transmission Provider and the Transmission Requester shall stipulate to a suspension of such filed rate for [time period], or such other period of time as agreed to by the Transmission Provider and the Transmission Requester. With regard to such filing with FERC, the Transmission Requester may contest the resolution of the matter described in Section 5.4.7 as set forth in such tariff or tariff amendment but may not contest, and shall fully support, the terms and conditions determined pursuant Section 5.4.7.1. Following the conclusion of the FERC proceeding regarding such tariff or tariff amendment, the Transmission Provider and the Transmission Requester shall execute and deliver a contract reflecting the terms of such tariff or tariff amendment.

5.4.8 No Agreement Regarding FERC-Jurisdictional Matter Being Fundamentally Different From FERC Policy. If the Transmission Provider and the Transmission Requester do not agree (each in its sole discretion) that the resolution of any matter subject to FERC jurisdiction submitted to a Dispute Resolution Proceeding is fundamentally different from any resolution of such a matter theretofore approved by FERC in a currently-applicable rule or precedential determination respecting the same or similar service, so that there are no usable standards to apply in rendering an award consistent with Section 5.4.3.2, such issue (including any *other matter regarding rate, rate methodology/design, and other term or condition of service which remains unresolved) shall be

submitted to a Dispute Resolution Proceeding. Subject to Section 5.4.5, if the Dispute Resolution Procedure panel determines that the resolution of such matter subject to FERC jurisdiction:

5.4.8.1 Is fundamentally different from any resolution of such a matter theretofore approved by FERC in a currently-applicable rule or precedential determination respecting the same or similar service, then the Transmission Provider and the Transmission Requester shall proceed as provided in Section 5.4.7; or

5.4.8.2 Is not fundamentally different from any resolution of such a matter theretofore approved by FERC in a currently-applicable rule or precedential determination respecting the same or similar service, then the Transmission Provider and the Transmission Requester shall proceed as provided in Sections 5.4.3 and 5.4.4.

5.4.9 Generic FERC Filing Permitted; Generic Filing Has No Precedential Value Regarding Pending Dispute Resolution Proceeding and No Impact on Pending Transmission Requests. No Member shall be restricted under these Bylaws from filing a generic tariff with FERC under Section 205 of the FPA and no other Member shall be restricted under these Bylaws from intervening and objecting to such generic tariff. The filing of a generic tariff with FERC under Section 205 of the FPA shall have no (i) FERC-precedential value with respect to any Dispute Resolution Proceeding initiated prior to the filing of such generic tariff or (ii) adverse impact on a Transmission Requester which initiates any request for transmission service under these Bylaws prior to the filing of such generic tariff.

5.5 Assignment of Transmission Services.

5.5.1 Conditions of Assignment. Transmission service shall be assignable by a Transmission Requester, provided that (i) written notice of the proposed assignment is provided to the Transmission Provider at least 90 days prior to the effective date of the proposed assignment, (ii) the Transmission Provider's system use and reliability are not adversely affected, (iii) the assignee agrees to accept and discharge all obligations associated

submitted to a Dispute Resolution Proceeding. Subject to Section 5.4.5, if the Dispute Resolution Procedure panel determines that the resolution of such matter subject to FERC jurisdiction:

5.4.8.1 Is fundamentally different from any resolution of such a matter theretofore approved by FERC in a currently-applicable rule or precedential determination respecting the same or similar service, then the Transmission Provider and the Transmission Requester shall proceed as provided in Section 5.4.7; or

5.4.8.2 Is not fundamentally different from any resolution of such a matter theretofore approved by FERC in a currently-applicable rule or precedential determination respecting the same or similar service, then the Transmission Provider and the Transmission Requester shall proceed as provided in Sections 5.4.3 and 5.4.4.

5.4.9 Generic FERC Filing Permitted; Generic Filing Has No Precedential Value Regarding Pending Dispute Resolution Proceeding and No Impact on Pending Transmission Requests. No Member shall be restricted under these Bylaws from filing a generic tariff with FERC under Section 205 of the FPA and no other Member shall be restricted under these Bylaws from intervening and objecting to such generic tariff. The filing of a generic tariff with FERC under Section 205 of the FPA shall have no (i) FERC-precedential value with respect to any Dispute Resolution Proceeding initiated prior to the filing of such generic tariff or (ii) adverse impact on a Transmission Requester which initiates any request for transmission service under these Bylaws prior to the filing of such generic tariff.

5.5 Assignment of Transmission Services.

5.5.1 Conditions of Assignment. Transmission service shall be assignable by a Transmission Requester, provided that (i) written notice of the proposed assignment is provided to the Transmission Provider at least 90 days prior to the effective date of the proposed assignment, (ii) the Transmission Provider's system use and reliability are not adversely affected, (iii) the assignee agrees to accept and discharge all obligations associated

with such assigned transmission service upon commercially reasonable terms and conditions approved by the Transmission Provider, which approval shall not be unreasonably withheld, and (iv) the assignee is a Member. Notwithstanding this Section 5.5.1, assignment may be made to any entity generating electric energy for sale for resale as defined in Section 211 of the FPA if no Member is willing to accept such assignment.

5.5.2 No Profit from Assignment. No Transmission Requester shall assign any of its rights to transmission service obtained under these Bylaws for more than the cost of such transmission service rights to such Transmission Requester.

5.6 Stranded Investment. Compensation for stranded investments shall only be made for those transmission investments which were made as a result of a legal requirement or contractual obligation on behalf of the Member whose request for transmission service or proposal to construct transmission facilities would cause such stranded investment. The Transmission Provider shall be compensated for quantifiable costs associated with stranded investment only to the extent and in a manner as permitted by then current FERC policy.

5.7 Curtailment of Transmission Services;. Curtailment of transmission service provided pursuant to these Bylaws shall take place in the following priority except as otherwise provided herein: (i) first, curtailments shall be among all Interruptible Transmission Service; and (ii) second, curtailments shall be pro rata among all Firm Transmission Service.

By mutual agreement among the affected Members, curtailment provisions may vary from this priority and prices for transmission service may reflect this variation. Power flow problems associated with any system contingencies will be handled through reasonable curtailment provisions consistent with this Section 5.7.

In the event continuity of service within the control area which is providing the transmission service is being jeopardized, the control area operator shall take whatever action it deems necessary in accordance with Prudent Utility Practice in order to terminate the system jeopardy condition and, in connection therewith, to preserve and maintain the safety, integrity and operability of the transmission system utilized to provide transmission service, to maintain to the maximum extent practicable the availability of such

transmission system, to protect the health and safety of employees and the public, and to minimize any adverse environmental effects. As used in this Section 5.7, "system jeopardy" shall mean an unplanned event or circumstance or a series of events or circumstances which results in, or threatens to result in, termination of continuity of service on the transmission system providing the transmission service.

5.8 Tax Exempt Financing.

5.8.1 No Impairment of Tax-Exemption. Notwithstanding any other provision of these Bylaws except the provisions of Sections 5.8.3 or 5.8.4, no Transmission Provider shall be required to provice transmission service to a Transmission Requester in a manner that would (i) impair the exclusion from federal gross income of interest paid (or to be paid) on any tax-exempt debt issued, or expected to be issued, by (or for the benefit of) the Transmission Provider, or (ii) impair the deductibility of interest expense associated with interest paid (or to be paid) on any such tax-exempt debt. If no such impairment exists, a Transmission Provider shall be required to provide transmission service to a Transmission Requester as otherwise provided in these Bylaws.

5.8.2 Nationally Recognized Bond Counsel/Private IRS Letter Ruling. At the direction of the Transmission Requester, the Transmission Provider shall consult with nationally recognized bond counsel to obtain an opinion of the extent, if any, of the impairment. The Transmission Requester may also direct the Transmission Provider to prepare and submit to the Internal Revenue Service a request for private letter ruling seeking clarification of the extent (if any) of the impairment. The Transmission Requester shall reimburse all reasonable costs incurred by the Transmission Provider in seeking such bond counsel opinion and/or private letter ruling.

5.8.3 Transmission Service Causes Impairment. If, based on consultation with nationally recognized bond counsel or the IRS's private letter ruling, the Transmission Provider determines that a Transmission Requester's transmission service request would cause such impairment, the Transmission Provider shall determine and provide

to the Transmission Requester the lowest reasonable cost of refinancing, reconfiguring or otherwise restructuring such tax-exempt debt such that the requested service could be provided. Such costs shall include, among other things, costs associated with (i) the loss of exclusion from federal gross income of interest paid (or to be paid) on any tax-exempt debt issued, or expected to be issued, by (or for the benefit of) the Transmission Provider regarding facilities necessary to provide such requested transmission service, and (ii) the loss of deductibility of interest expense associated with interest paid (or to be paid) on any such tax-exempt debt. If the Transmission Requester agrees to pay to the Transmission Provider such costs, in addition to payment of all other costs as provided under these Bylaws, the Transmission Provider shall be required to provide the requested transmission service pursuant to the provisions of these Bylaws.

5.8.4 Determination of Cost of Refinancing. If, after exercising due diligence to determine the lowest reasonable cost of refinancing, reconfiguring or otherwise restructuring such tax-exempt debt, the Transmission Provider is unable to determine the amount of such costs with reasonable accuracy, the Transmission Provider's obligation to provide the requested service shall terminate; provided, however, that such obligation to provide the requested service shall not terminate in the event that the Transmission Requester posts a bond of sufficient size or provides other assurances that it shall fully compensate the Transmission Provider for those additional costs as they become known. If the Transmission Requester posts such bond or provides such other assurances, or said costs are subsequently determined with reasonable accuracy, the Transmission Requester shall have the option of compensating the Transmission Provider for such lowest reasonable cost of refinancing in which case the Transmission Provider shall provide the requested transmission service pursuant to the provisions of these Bylaws.

5.8.5 Financing of New Facilities. Any Member who funds new transmission facilities with tax-exempt financing after the date the Member joins WATSCO, shall, at no additional cost to such Member unless reimbursed by other Members, undertake all reasonable actions to minimize: (i) any

restrictions on a Transmission Requester's access to such facilities caused by the tax-exempt status; and (ii) any increase in the price of transmission service resulting from the refinancing, reconfiguring, or otherwise restructuring of such tax-exempt debt in order to provide service to a Transmission Requester.

5.9 **Retail Wheeling.** Nothing in these Bylaws shall require any Member to participate in, or plan with respect to, any retail wheeling arrangement. Nothing in these Bylaws shall prohibit any Member (in its sole and absolute discretion) from participating in, or planning with respect to, any retail wheeling arrangement.

5.10 **Waiver of Rights to Request Service Under The FPA.** Except as mutually agreed between a Member requesting transmission service and a Member willing to provide transmission service, each Member waives its rights to request transmission service from a Member through FERC pursuant to Sections 211 and 212 of the FPA with respect to any transmission service which such Member has the right to obtain pursuant to these Bylaws.

6. **MEMBERS BOUND BY AND SUPPORT WATSCO DECISIONS; NOTIFICATION OF WATSCO REQUESTS, WATSCO CONTRACTS AND COMPLETION OF MEMBER'S PROJECT:**

6.1 **Certain Members Bound By Decisions.** Except as specifically provided otherwise in these Bylaws, each Member which participates in a process (or receives written notice that its rights may be affected thereby in sufficient time to participate in such process) resulting in a decision, resolution or action in connection with, resulting from or required by these Bylaws shall be bound by such result.

6.2 **Participating Members Support Decisions Before Regulatory Authorities.** Except as specifically provided otherwise in these Bylaws, each Member which participates in a process resulting in a decision, resolution or action in connection with, resulting from or required by these Bylaws shall fully support such decision, resolution or action in connection with, resulting from or required by these Bylaws before any Regulatory Authority.

6.3 **Submit Matters in Timely Manner to Obtain Review, Permit or Approval.** Except as specifically provided otherwise (i) by mutual agreement among affected Members or (ii) in

these Bylaws, each decision, resolution or action in connection with, resulting from or required by these Bylaws which requires any review, permit or approval shall be submitted in a timely manner in order to obtain such review, permit or approval.

6.4 **Notice of Transmission Requests.** The Planning Committee shall develop procedures which provide for each Member receiving a timely notice of the filing of a request for transmission service pursuant to Section 5 and applicable Appendix A of these Bylaws.

6.5 **Notice of Execution of WATSCO Contracts.** The Planning Committee shall develop procedures which provide for each Member receiving a timely notice of the execution and delivery of a contract providing transmission service between two or more Members as a result of a transmission service request pursuant to Section 5 and the applicable Appendix A of these Bylaws.

6.6 **Notice of Completion of Transmission Facilities.** The Planning Committee shall develop procedures which provide for each Member receiving a timely notice of the completion of new transmission facilities which have a rating of, or increase the rating of existing facilities by, over 100 kV.

7. **NO IMPACT ON CONTRACTS; ABILITY TO CONTRACT OUTSIDE WATSCO; NEGOTIATE CONTRACTS CONSISTENT WITH BYLAWS:**

7.1 **No Impact on Contracts or Other Legal Obligations.** These Bylaws do not replace or modify, supersede, or limit any contract, decision of regulatory agencies or courts of law, or other legally enforceable entitlement or rights of any Member except as specifically provided herein.

7.2 **Negotiated Agreements Notwithstanding Bylaws.** Notwithstanding any provision of these Bylaws to the contrary, any Member may agree and/or contract with any other Member regarding any mutually agreeable term or condition for transmission service.

7.3 **Good Faith Efforts to Negotiate Contracts Under Bylaws.** Each Member shall make good faith efforts to negotiate definitive contracts, as appropriate, to provide requested transmission service, including any Incremental Additions, in accordance with these Bylaws.

8. GOVERNANCE:

8.1 Initial Membership Eligibility; Ex Officio Members.

8.1.1 Initial Membership. Membership in WATSCO shall be open to any entity generating electric energy for sale for resale as defined in Section 211 of the FPA and all publicly owned and investor owned electric utilities, rural electric cooperatives, Federal power marketing agencies, state agencies owning or planning transmission or generation, joint powers agencies of electric utilities, non-utility generators, and other transmission owners.

8.1.2 Regulatory/Governmental Agencies Ex Officio Members; Rights of Such Members. Representatives of appropriate regulatory and/or governmental agencies may be ex officio members of the Board of Directors and the Planning Committee. The Board of Directors shall designate from time to time no more than two representatives from such regulatory and/or governmental agencies from each State in which a Member is subject to such regulatory and/or governmental agency to be ex officio members of the Board of Directors and the Planning Committee. Each such representative shall be entitled to exercise any right any other Member may exercise under these Bylaws, including but not limited to: participating in all meetings or proceedings under these Bylaws in the same manner as other Members; and receiving notices, information and data under these Bylaws in the same manner and under the same procedures as other Members; provided, however, such representative shall have no voting rights on the Board of Directors or the Planning Committee.

8.2 Membership Following Effective Date of Bylaws. Following the effective date of WATSCO, non-Member entities desiring to join WATSCO and who meet the eligibility requirements of Section 8.1 must submit to the Board written requests for membership. Membership must be granted unless (i) the Board finds by a 2/3 majority vote of each category of Members that the entity seeking membership is ineligible for membership under these

Bylaws or (ii) the entity seeking membership was previously expelled under the terms of Section 8.4. Any non-Member who is denied Membership under these Bylaws may appeal such denial to FERC.

8.3 Withdrawal from Membership.

8.3.1 Right of Withdrawal From Membership. Any Member may withdraw from membership effective upon receipt by the Board of written notice thereof. Any request for transmission service pursuant to Section 5 and the applicable Appendix A with a notice date prior to the effective date of withdrawal shall be processed and determined pursuant to the provisions of these Bylaws in effect as of the date of withdrawal as if the withdrawing Member were still a member of WATSCO. Any request for transmission service pursuant to Section 5 and the applicable Appendix A shall be deemed null and void if prior to the completion of processing such request for transmission service pursuant to these Bylaws the Transmission Requester shall withdraw from membership in WATSCO.

8.3.2 Withdrawal No Effect on Contracts. A Member's withdrawal of its membership in WATSCO pursuant to this Section 8.3 shall have no effect on the validity or enforceability of any contract or decision rendered pursuant to a Dispute Resolution Proceeding in accordance with these Bylaws which are in effect as of the effective date of withdrawal.

8.4 Members Subject to Disciplinary Action.

8.4.1 Bad Faith Conduct of Members. Upon receipt by the Board of a written complaint of a Member alleging that another Member has engaged in bad faith conduct under Section III E. of the applicable Appendix A or has engaged in any other bad faith conduct in connection with any duty or obligation arising out of the Bylaws, including any resolution or other action implementing the Bylaws, or arising out of any Dispute Resolution Proceeding decision, the Board or its designee, shall conduct a reasonable inquiry into such allegations. If the Board or its designee, following a

reasonable inquiry, finds that a Member has engaged in bad faith conduct, then the Board, on a 2/3 majority vote, shall take appropriate disciplinary action, which may include but shall not be limited to any of the following (including any combination thereof):

i) Issue a written reprimand and warning;

ii) Deny the offending Member the right to make or participate in a transmission request pursuant to these Bylaws for an appropriate period of time;

iii) Deny the offending Member the right to participate in the project or matter that was the subject of the bad faith conduct;

iv) Deny the offending Member the right to request transmission service over such project facilities for an appropriate period of time; or,

v) Expel the offending Member from WATSCO, provided that said expulsion shall have no effect on the validity or enforceability of any contract or Dispute Resolution Proceeding decision which is in effect as of the effective date of the expulsion.

8.4.2 Factors the Board May Consider Regarding Disciplinary Actions for Members; Decision Not Subject to Dispute Resolution Procedures. In determining an appropriate disciplinary action, the Board may consider the following factors: i) the egregiousness or willfulness of the bad faith conduct; ii) any past bad faith conduct of the Member regarding WATSCO-related matters; iii) the adverse consequences of such bad faith conduct on other Members; iv) the willingness of the Member to refrain from such conduct in the future; v) the long term effect of the proposed disciplinary action on WATSCO and its Members; and, vi) any other factor relevant to the rendering of a fair and just disciplinary action.

The decision of the Board imposing disciplinary action under this section shall

be final, and shall not subject to the Dispute Resolution Procedure.

The Board may adopt procedural rules for conducting hearings and receiving evidence concerning allegations of bad faith conduct. Any disciplinary action provided under this section shall not be deemed to be an exclusive remedy, but shall be in addition to any legal or equitable remedy that is available to an aggrieved Member.

8.4.3 Arbitrary or Capricious Conduct of Regulatory Agencies. Upon receipt by the Board of a written complaint of a Member alleging that a state regulatory agency or a local governing board acting as a regulatory agency, has arbitrarily or capriciously overturned, nullified, or conditioned in any material respect any agreement or Dispute Resolution Proceeding decision reached in accordance with these Bylaws, and that Member has been adversely and substantially affected by such conduct, the Board or its designee, shall conduct a reasonable inquiry into such allegations. If the Board or its designee, following a reasonable inquiry, finds that the regulatory agency has engaged in arbitrary or capricious conduct in overturning, nullifying, or conditioning in any material respect any agreement or Dispute Resolution Proceeding decision reached in accordance with these Bylaws, then the Board may, on a 2/3 majority vote, take appropriate disciplinary action against the Member regulated by such agency, which may include but shall not be limited to any of the following (including a combination thereof):

i) deny the Member regulated by such agency the right to make or participate in a transmission request pursuant to these Bylaws for an appropriate period of time;

ii) Deny the Member regulated by such agency the right to participate in the project or matter that was the subject of the arbitrary or capricious conduct;

iii) Deny the Member regulated by such agency the right to request transmission service over such project facilities for an appropriate period of time;

iv) Expel the Member regulated by such agency from WATSCO, provided that said expulsion shall have no effect on the validity or enforceability of any contract or Dispute Resolution Proceeding decision reached in accordance with these Bylaws which are in effect as of the effective date of the expulsion.

8.4.4 Factors the Board May Consider Regarding Disciplinary Action for Regulatory Agency; Decision Not Subject to Dispute Resolution Procedures. In determining the appropriate disciplinary action, the Board may consider the following factors: i) the egregiousness or willfulness of the bad faith conduct; ii) any past arbitrary or capricious conduct of such agency regarding WATSCO agreements or Dispute Resolution Proceeding decisions; iii) the adverse consequences of such arbitrary or capricious conduct on other Members; iv) the long term effect of the proposed discipline on WATSCO and its Members; and, v) any other factor relevant to the rendering of a fair and just disciplinary action.

The decision of the Board imposing disciplinary action under this section shall be final, and shall not be subject to the Dispute Resolution Procedure.

The Board may adopt procedural rules for conducting hearings and receiving evidence concerning allegations of capricious or arbitrary conduct of regulatory agencies.

For purposes of this Section 8.4.4, "arbitrary or capricious" conduct shall include, the regulatory agency's failure to give substantial deference, without justification or good cause, to any agreement or dispute resolution decision reached in accordance with these Bylaws.

8.4.5 Effect of Expulsion. In the event that a Member is expelled pursuant to Sections 8.4.1 or 8.4.3, an request for transmission service pursuant to these Bylaws shall be null and void as of the effective date of such expulsion.

8.5 **List of Members.** Appendix B lists the entities which are Members of, have been added to, have withdrawn from, have been expelled from, or have been reinstated as Members of WATSCO. The dates of each such event shall be included in Appendix B.

8.6 **Board Composition.** WATSCO shall be governed by a Board of Directors consisting of: (i) three representatives elected by investor owned electric utility Members; (ii) three representatives elected by publicly owned electric utility Members and joint powers agencies; (iii) three representatives elected by non-utility generator Members; and (iv) three representatives from the group of Members made up of Federal power marketing administrations, rural electrical cooperatives, and state agencies owning transmission. No entity having subsidiary entities shall have more than one representative on the Board. The Board of Directors shall designate from time to time no more than two representatives from regulatory and/or governmental agencies from each State in which a Member is subject to such regulatory and/or governmental agency to be ex officio members of the Board of Directors. Such representatives shall have those rights set forth in Section 8.1.2 but shall have no voting rights on the Board of Directors.

8.7 **Initial Representatives on Board.** The initial representatives on the Board of Directors for each category/group identified in Section 8.6 shall be appointed by the respective Members of each such group which initially execute these Bylaws. Such Members in each such group shall identify the term of office for each representative in their respective representative group.

8.8 **Board Term.** Board terms shall be for three years provided that initially one third of the Board members in each category shall serve for one year, one third for two years, and one third for three years as determined in Section 8.6.

8.9 **Board Election.** Election to the Board shall require a majority vote of the current members of each category of

membership provided for in Section 8.6. If for any reason a category of membership does not or cannot elect a representative to all of its three Board positions, the open Board position(s) shall remain vacant until the next annual meeting. Once filled, if a seat on the Board becomes vacant for any reason, a special election of the appropriate membership category shall be held to fill that vacant seat for the remainder of the unexpired term.

8.10 Board Action. All matters regarding WATSCO, including the annual budget and level and structure of Member dues, shall be decided by a 2/3 majority vote of the Board members currently holding office, unless otherwise provided in the Bylaws.

8.11 Amendments to These Bylaws. Any changes to the Bylaws must be approved by a 2/3 majority vote of each category of Membership described in Section 8.6 of those Members in attendance at the annual meeting after recommendation from a 2/3 majority vote of each category of membership currently holding office on the Board.

8.12 Voting of Board of Directors. All votes of the Board, whether taken by the Board as a whole or the membership category described in Section 8.6 shall be on a one Member one vote basis.

8.13 Board Officers. Immediately following the adjournment of the annual meeting, the Board of Directors shall meet and organize by electing a President, Vice President, Secretary and Treasurer provided that the offices of the Secretary and Treasurer may be combined in one person. The President shall preside at all meetings of the Board. In case of the absence or disability of the President, the duties of that office shall be performed by the Vice President.

8.14 President Appoints Committees. The President may, with the approval of a 2/3 majority of the Board, appoint committees, hire staff and enter into contracts on behalf of WATSCO as appropriate.

8.15 Adoption of Rules by Board; List of Qualified Arbitrators. The Board shall adopt rules, regulations and policies to implement and accomplish the purposes and provisions of these Bylaws as necessary and shall adopt a list of qualified arbitrators.

8.16 Annual Meeting. An annual meeting of all WATSCO Members shall be held for the purpose of electing Board members,

approving the budget and considering any Board proposed changes to the Bylaws as necessary. The first meeting shall be as soon as practicable following the effective date of these Bylaws. Subsequent annual meetings shall be at a time and location determined by the Board.

8.17 **Board Duties, Powers and Responsibilities.** The Board of Directors shall have the following duties, powers and responsibilities:

(i) Adopt rules, regulations and policies to implement and accomplish the purposes and provision of these Bylaws as necessary;

(ii) Adopt lists of qualified arbitrators;

(iii) Exercise general supervision over the Planning Committee and other committees established pursuant to these Bylaws, and review, discuss and attempt to resolve any disputes within any such committee;

(iv) On request, review, discuss and attempt to resolve any disputes among any of the Members relating to WATSCO not otherwise covered by these Bylaws;

(v) Review, modify and approve or disapprove all budgets and revisions thereof prepared and submitted with respect to WATSCO;

(vi) Consider any matters relating to the general supervision of WATSCO proposed by any Member;

(vii) Delegate any of its duties or responsibilities to the Planning Committee or any committee established pursuant to these Bylaws;

(viii) Perform such other functions and duties as may be provided for in these Bylaws, or as may otherwise be appropriate; and

(ix) Provide for the auditing of the use and management of moneys budgeted as provided by these Bylaws.

9. **PLANNING COMMITTEE:** The Planning Committee is primarily established to provide a forum for the development of fully coordinated plans for regional and subregional transmission use and additions. The Planning Committee which shall, among other things:

(i) Establish a repository of system data from which Members may obtain information necessary to conduct coordinated transmission planning;

(ii) Coordinate the transmission planning activities of Members;

(iii) Encourage all Members to seek membership in WSCC in order to maximize consistency of data, minimize disputes over access to data and models, and reduce the need for duplicative study efforts; and

(iv) Develop WATSCO planning criteria for recommendation to the Board of Directors.

9.1 **Establish Data Base.** The Committee shall establish a data base, including adequate documentation of assumptions, that may be used for modeling of the electrical system. This data base shall include detailed information about the existing and planned transmission system and generating resource operating data sufficient to allow any Member to model and determine the transfer capability with respect to a proposed transmission service request or project. Members shall provide the Planning Committee with adequate electrical system data, system operating assumptions, and all other information as needed to permit other Members to evaluate transmission system performance. The information shall be adequate to evaluate the availability of requested transmission service or the need for and impacts of new transmission facilities. To the maximum extent feasible the Planning Committee shall provide that the information be supplied in the form and format required for other purposes so as to avoid unnecessary duplication.

9.2 **Data Base Addresses Planning Needs.** The Planning Committee shall take all steps available to ensure that the transmission facility planning needs of Members are adequately addressed with the data base.

9.3 **Compile and Update Plans.** The Planning Committee shall compile and update on a biennial basis, the Members' transmission and resource plans into a consolidated document.

9.4 **Make Recommendations.** The Planning Committee may make recommendations to the Members and the Board regarding the adequacy of inter- and intra-control area

transmission transfer capability to meet the reasonable needs of Members.

9.5 **Information Available to Members.** The Planning Committee shall ensure that all studies and information are available to all Members.

9.6 **Undertake other Activities Directed by Board.** The Planning Committee may undertake such other activities as directed by the Board.

9.7 **Membership on Planning Committee.** Each Member utility that operates a control area, each Member Power Marketing Administration and each Member state agency owning transmission shall be entitled to a permanent seat on the Planning Committee. Additional utility membership shall be equal to the number of utilities operating control areas. The number of investor owned utility members, publicly owned utility members and non utility generator members of the planning committee shall be equal. As provided in Section 8.1.2, the Board of Directors may designate from time to time no more than two representatives from regulatory and/or governmental agencies from each State, including the State of California, in which a Member is subject to such regulatory and/or governmental agency to be ex officio members of the Planning Committee. Such representatives shall have those rights set forth in Section 8.1.2 but shall have no voting rights on the Planning Committee.

Each Member entitled to a seat on the Planning Committee shall appoint one duly authorized representative to the Planning Committee and shall designate such individual as its representative on the Planning Committee by giving notice to the Secretary of the Planning Committee. Each Member or group of Members may, by giving notice to the Secretary of the Planning Committee, designate an alternate or alternates to act as it or their, as the case may be, representative on the Planning Committee in the absence of the regular member or to act on specified occasions with respect to specified matters, such notice to be effective upon receipt by the Secretary of the Planning Committee.

9.8 **Meetings Open to Members.** Meetings of the Planning Committee shall be open to any Member and any Member may make recommendations and presentations to the Planning Committee. The Planning Committee may make decisions specified in these Bylaws and recommendations to the

Board upon a majority vote of the Planning Committee members.

9.9 **Regular Meetings; Notice; Minutes.** The Chairman of the Planning Committee shall call regular meetings of the Committee. The Chairman shall promptly call a meeting of the Planning Committee at the request of a majority of representatives on the Planning Committee, or their designated alternates. Adequate notice shall be given of each Planning Committee meeting to all Planning Committee members at least four weeks in advance. The Secretary shall prepare formal minutes of the meetings. Such formal minutes shall be prepared and typed for each meeting. Copies of such written minutes shall be corrected and approved by the Planning Committee at its next meeting and submitted to the Board.

9.10 **Officers of Planning Committee.** Officers of the Planning Committee shall be elected by the Committee members. The officers of the Planning Committee shall be a Chair, Vice-Chair, and Secretary. The terms of each such office shall be determined by the Planning Committee members.

9.11 **Subcommittees.** Subcommittees of the Planning committee may be established from time to time by the Chair, subject to confirmation by the Planning Committee, and shall consist of such Members as may be appointed by the Chair and confirmed by the Planning Committee.

10. DISPUTE RESOLUTION:

10.1 **Scope of Matters Subject to Dispute Resolution Procedure.** With respect to any matter under these Bylaws, each Member involved in negotiations with any other Member shall make good faith efforts to settle any disputes which may arise. Nevertheless, in the event any such dispute is not settled, each Member agrees that any such dispute, except as hereinafter specifically described, shall be subject to the Dispute Resolution Procedure as set forth in Section 5.4 and this Section 10, and any Member may, after good faith efforts to resolve the dispute, declare the dispute at an impasse and commence the Dispute Resolution Process.

10.1.1 <u>All Matters Subject to Dispute Resolution Procedure Except For Specifically Identified Matters.</u> Except as specifically provided in Section 10.1.2, all disputes arising out of any matter relating to these Bylaws are subject to the Dispute Resolution Procedure.

The partial listing of matters subject to the Dispute Resolution Procedure (except as noted) set forth below, and the failure to list other matters which are not excluded in Section 10.1.2, shall not in any way be construed as a limitation regarding matters subject to the Dispute Resolution Process. Matters subject to the Dispute Resolution Process (except as noted herein) shall include, but not be limited to:

(i) Amounts and location of Available Transmission Capacity;

(ii) Extent of Ownership-Like Rights;

(iii) Prices, terms and conditions of transmission service as set forth in Section 5.4;

(iv) The assumptions which do not have the force of law and/or results of any modeling or methodology utilized by any Member in connection with the determination of Available Transmission Capacity or the pricing of transmission service under these Bylaws, and the consistent application thereof; provided, however, the use by such Member of such modeling or methodology for purposes other than with respect to these Bylaws shall not be subject to Dispute Resolution Procedure;

(v) The determination whether the proposed project in Section 4.3 meets the minimum reliability criteria described in Section 4.2 or reduces pre-existing transfer capability at points of interconnection between Members' systems; and

(vi) The determination of costs associated with Incremental Additions and other matters relating to Incremental Additions set forth in Sections 5.3.3 through 5.3.7.

10.1.2 Matters Which Are Not Subject to Dispute Resolution Procedure. The following matters (except as noted) under these Bylaws shall not be subject to the Dispute Resolution Procedure:

(i) The selection of the physical means or facilities by which a Transmission Provider provides transmission service to a Transmission Requester provided that the costs of such transmission service or Incremental Addition is capped at the lowest cost reasonable alternative;

(ii) Existing published reliability criteria, standards and guidelines of the Western Systems Coordinating Council and the North American Electric Reliability Council shall be deemed to be consistent with Prudent Utility Practice;

(iii) The reliability criteria, standards, and guidelines of a Member utility, which were published as of January 1, 1992, shall be rebuttably presumed to be consistent with Prudent Utility Practice; provided, however, no such rebuttal presumption shall apply to any changes to such criteria, standards and guidelines, and specific provisions of such criteria, standards or guidelines shall be subject to the Dispute Resolution Procedure on the grounds of inconsistency with Prudent Utility Practice (rebuttable presumption must be overcome) or that such criteria, standards and guidelines are inconsistently applied as to the Member's own expected uses or similar expected uses of other Members;

(iv) Executed contracts;

(v) Legitimacy of any Transmission Requester's request for transmission service pursuant to Section 5 and the applicable Appendix A;

(vi) Any issues related to ownership of facilities in connection with transactions outside of these Bylaws;

(vii) For purposes of determining Planned Native Load, forecasts of service area demand adopted following a public hearing by a state's energy planning agency and any assumptions subject to a regulatory agency order shall be conclusively presumed correct in any Dispute Resolution Proceeding; and

(viii) Compensatory damages with respect to any matter under these Bylaws.

10.2 Dispute Resolution Procedure.

10.2.1 Mailing List. The Board or its designee shall maintain a current mailing list containing the names of all Members and the names of all non-Members whose interests may be affected by WATSCO disputes (as determined by the Board or its designee)(the "Mailing List"), including the names and addresses of their representatives or process agents for purposes of receiving service (see Section 10.2.7 below).

10.2.2 Initiating Member Notice. Any Member may call for submission to Dispute Resolution Procedure of a matter in dispute the subject of which is not listed in Section 10.1.2. The Member calling for the Dispute Resolution Proceeding (the "Initiating Party") shall serve a written Notice on: (i) the other Member(s) to the dispute (the "Respondent"), all names appearing on the Mailing List, and the Board. The Initiating Party and/or the Respondent may be more than one Member.

10.2.3 Form of Notice; Appointment of Panel. The Notice shall be in a form approved by the Board, and shall, at a minimum, describe: (i) the nature of the dispute; (ii) a statement of issues to be resolved in the Dispute Resolution Process; (iii) the Initiating Party's position on each issue; and, (iv) the requested remedy or relief. With respect to Section 5.4.3 the Notice shall also include a list of terms and conditions agreed to between the Initiating Party and the Respondent.

Such Notice shall also call for the appointment of a panel of arbitrators (the "Panel"). The Initiating Party shall indicate its choice of an arbitrator in the Notice. If the Initiating Party includes more than one Member, the Notice and the selection of the arbitrator shall be prepared jointly.

10.2.4 Form of Response. Within thirty (30) days from receipt of such Notice, each Respondent shall serve the Initiating Party and the Board with a written response in a form approved by the Board (the "Response"). The Response shall, at a minimum, describe: (i) the nature of the dispute; (ii) a statement of issues to be resolved in the Dispute Resolution Proceeding; (iii) the Respondent's position on each issue; and, (iv) the recommended remedy or relief, if any.

The Respondent shall also provide a copy of its Response to any entity on the Mailing List requesting a copy thereof within five (5) days of the request.

10.2.5 Name Second Arbitrator. In addition to the above information, the Respondent shall provide in its Response the name of a second arbitrator. If there are multiple Respondents, such Respondents shall meet and confer in good faith to select a second arbitrator. If the multiple Respondents are unable to do so within twenty (20) days of receipt of the Initiating Party's Notice, then the Respondents shall notify the Board, and the selection of the second arbitrator shall be in accordance with the provisions of Section 10.3.3 below.

10.2.6 Notice of Motion to Intervene. A Member or non-Member having preexisting rights which could be affected by such dispute and desiring to intervene in the Dispute Resolution Proceeding shall, within thirty (30) days of receipt of the Initiating Party's Notice, file a Notice of Motion to Intervene. The Notice of Motion to Intervene shall be in a form approved by the Board. No Member or non-Member may intervene in a Dispute Resolution Proceeding without first serving a timely Notice of Motion to Intervene on the Initiating Party, the Respondent, and the Board. The proposed intervenor shall also provide a copy of its Notice of Motion to Intervene to any entity on the Mailing List requesting a copy thereof within five (5) days of the request.

10.2.7 Preparation of Service List. Upon expiration of the 30-day period for Notice of Intervention, the Initiating Party shall prepare a Service List comprised of the names and addresses of: the Initiating Party, the Respondent, the Board, and all entities who have served a timely Notice of Motion to Intervene. The Initiating Party shall serve a copy of the Service List on each entity therein contained within five (5) days following the expiration date for submission of a Notice of Motion to Intervene.

10.2.8 Motion to Intervene. Each entity filing a Notice of Motion to Intervene shall serve a Motion to Intervene on all entities on the Service List within thirty (30) days of receipt of the Service List. The Motion shall be in a form approved by the Board. The Motion shall, at a minimum, provide:

(i) a full statement explaining the intervenor's interest in the Dispute Resolution Proceeding, how the intervenor may be affected by the Dispute Resolution Proceeding, and why the proposed intervenor is an indispensable party to the Dispute Resolution Proceeding;

(ii) the intervenor's position on each issue set forth in the Initiating Party's Notice and the Response;

(iii) a statement of any additional issues to be submitted in the Dispute Resolution Proceeding;

(iv) the intervenor's recommended remedy or relief, if any, with respect to issues described in (ii) and (iii) above; and,

(v) in the case of an intervening non-Member, a signed statement that such non-Member agrees to be subject to and bound by the decision in the Dispute Resolution Proceeding, and shall further agree to support such decision in any subsequent regulatory proceeding, subject to the right of appeal as provided in Section 10.6.

10.2.9 Service of Process. For purposes of this Section 10.2.9, "service" of a notice, filing, or document shall be either: by personal delivery to the party's representative or process agent (see Section 10.2.7); or, by certified mail, return receipt requested, to such representative or process agent.

10.3 Arbitration Panel Selection

10.3.1 List of Arbitrators. The Board shall maintain lists of arbitrators nominated by each category of membership on the Board. Each entity represented by the Board shall have the right to add the name of a potential arbitrator to the appropriate list. Additions to the lists shall be made at an annual meeting called by the Board for this purpose.

Each entity represented by the Board shall also have the right by way of majority vote of the entity's interest group to remove the name of any arbitrator that appears on the list at any time. It shall be the responsibility of the Board to maintain an adequate number of potential arbitrators to cover any disputes that may arise under these Bylaws. Notwithstanding the provisions of this Section 10.3, the Initiating Party and the Respondent may jointly agree to any selection of arbitrators of their choosing, so long as the number of arbitrators selected for the Panel does not exceed three.

No person shall be eligible for appointment as an arbitrator who is an officer, member of the governing body, employee, consultant, of any of the parties to the dispute or is otherwise interested in the matter to be submitted to the Dispute Resolution Process. Panel members should be knowledgeable in matters involving the electric utility industry. Panel members must disclose to the Parties and intervenors any potential interest they may have in the dispute and are obliged to disqualify themselves from the Dispute Resolution Proceeding in accordance with the American Bar Association Code of Judicial Conduct.

10.3.2 Selection of Arbitrators for Panel. The Initiating Party and the Respondent shall each select an individual from the list of arbitrators as provided in Section 10.3.1. The two selected arbitrators shall, within twenty (20) days of being notified by the Board of their selection for such Dispute Resolution Proceeding, choose and appoint a third arbitrator from the list of arbitrators.

The three arbitrators shall constitute the Panel for the dispute. If an Initiating Party or Respondent refuses to select an arbitrator within ten (10) days of submitting its Notice or Response, such Initiating Party or Respondent shall be deemed to have forfeited all rights to participate in the Dispute Resolution Proceeding but shall be bound by the outcome of such Dispute Resolution Proceeding as if it had participated therein.

10.3.3 Impasse in Selection of Arbitrator (Multiple Respondents). In the case of multiple Respondents, if after meeting and conferring in good faith, the multiple Respondents are unable to jointly select an arbitrator, the Respondents shall so notify the Board. The Board, or a Board-appointed Dispute Resolution Procedure subcommittee, shall appoint an arbitrator from the list representing the respondents using the same voting procedure as set forth in Section 8.10 of these Bylaws.. The two selected arbitrators shall then proceed to select a third arbitrator pursuant to Section 10.3.2. The Board, or its subcommittee, shall not select more than one arbitrator from any one list representing a particular interest group of WATSCO. Notwithstanding this restriction, the Board, or its subcommittee, shall use its discretion to select a Panel that represents a fair balance of the respective interests involved in the dispute.

10.3.4 Replacement of Arbitrators. If a Panel member is removed or resigns, the process by which the absent Panel member was selected shall be used to select a successor arbitrator, with the time period for selection commencing on the date of the arbitrator's removal or

resignation. The same procedure shall be used to select a Panel member if the person whom a Party selects for the Panel is unable to fulfill his or her role as arbitrator due to other official commitments or illness.

10.4 Prehearing Conference. Within fifteen (15) days of the selection of the Panel, the Panel shall conduct a noticed prehearing conference. At or following the prehearing conference, the Panel shall undertake the following activities.

10.4.1 Rule on Motions to Intervene. The Panel shall rule on any Motions to Intervene, which ruling shall include a finding regarding the indispensability of the moving intervenor. An intervenor is indispensable ("Indispensable Intervenor") if: (a) the intervenor claims a direct and immediate interest relating to the property or transaction that is the subject of the dispute; (b) the intervenor's ability to protect that interest may as a practical matter be impaired or impeded by the disposition of the Dispute Resolution Proceeding; and, (c) the intervenor's interest is not adequately represented by the Initiating Party or Respondent. The Panel shall exclude from the Dispute Resolution Proceeding any intervenors whose issues are beyond the scope of the dispute or are inconsistent with the Bylaws.

In the event that a state or federal agency, including an ex-officio Member, qualifies as an Indispensable Intervenor, said agency or ex officio Member may fully participate in the Dispute Resolution Proceeding as a Party. Said agency or ex officio Member, however, shall not be entitled to submit a Proposal unless said agency or ex officio Member has expressly agreed in writing to be bound by the decision, and has the authority to be so bound.

If said agency or ex officio Member declines to agree to be bound by the decision, or lacks the authority to be so bound, then notwithstanding Sections 6.1 or 10.5.6, the Panel's decision shall not be binding upon said agency or ex officio Member. The agency

or ex officio Member shall, however, be entitled to file an advisory Proposal. The acceptance or rejection of such a Proposal is within the sole determination of the Panel under Section 10.5.1.

For purposes of this Section 10, "Party" or "Parties" shall mean the Initiating Party(ies), the Respondent(s), and the Indispensable Intervenor(s).

10.4.2 "Baseball" Arbitration Unless Special Circumstances Exist. "Baseball" arbitration shall be the method of dispute resolution under these Bylaws unless the Panel determines that "baseball" arbitration is unworkable, ineffective or inappropriate because of the existence of special circumstances. Such special circumstances may include: i) the presence of multiple Parties with multiple issues so that it is highly unlikely that a single Proposal will adequately and fairly address all issues and/or interests; or ii) the presence of other factors that render "baseball" arbitration ineffective, unworkable or inappropriate. If the Panel determines that "baseball" arbitration is ineffective, unworkable or inappropriate, then "regular" arbitration shall be utilized unless the Parties mutually agree to another method of dispute resolution. The Panel shall make a decision on the form of dispute resolution at the Prehearing Conference.

For purposes of this Section 10:

"Baseball" arbitration refers to a dispute resolution method where the Panel renders its decision by selecting a Proposal, in its entirety, of one of the Parties.

"Regular" arbitration refers to a dispute resolution method where no Proposal is submitted by the Parties, but rather the Panel, in its sole determination, fashions the remedy or resolution set forth in its decision.

10.4.3 Determine Issues. The Panel shall determine which issues submitted by Parties and Indispensable Intervenors best reflect the nature of the dispute outlined by the Parties and should be the subject of the Dispute Resolution Proceeding, or of a summary judgment proceeding (the "Panel's Statement of Issues"). As an alternative, the Panel may direct the Parties and Intervenors to meet and confer on a joint statement of issues (the "Joint Statement").

10.4.4 Establish Schedule. The Panel shall authorize necessary discovery and establish the Dispute Resolution Proceeding hearing schedule.

10.4.5 Solicit Proposal. If "Baseball" arbitration is utilized, the Panel shall solicit a Proposal from each party which Proposal shall include a proposed remedy for each issue that is the subject of the Dispute Resolution Proceeding; provided that with respect to any intervenor, such Proposal shall be limited to the extent of its interests in the subject matter of the Dispute Resolution Proceeding.

10.4.6 Schedule Procedural Matters. The Panel shall schedule summary judgment motions, discovery, and such other procedural matters as the Panel deems appropriate to a fair and expeditious resolution of the dispute.

10.4.7 Limitation of Requested Information. The Panel shall have no authority at the hearing to call for additional information not related to issues included in the Joint Statement or in the Panel's Statement of Issues.

10.5 Dispute Resolution Proceeding Decision.

10.5.1 Acceptance of One Proposal; Time Frame. Within twenty (20) days after the conclusion of the Dispute Resolution Proceeding hearing the Panel shall, by a majority vote, accept one of the submitted Proposals, without modification.

10.5.2 Factors and Standards Regarding Dispute Resolution Proceeding Decision. To determine which Proposal is the more reasonable, the

Panel shall specifically consider all factors relevant to the reasonableness of each Proposal, including, but not limited to, (i) the facts known and the facts that should have been known to each Party at the time of the action or inaction giving rise to the dispute, (ii) the time available in which to act, and (iii) other factors relevant under the circumstances. Except as otherwise specifically provided in Section 5.4, the Panel's decision shall be based upon which Proposal best meets the standards and intent of these Bylaws and is consistent with Prudent Utility Practice and applicable state or federal law (including the Federal Power Act). Where the Panel finds that the standards provided in this Section are insufficient in order for the Panel to render a decision, the Panel shall request the Planning Committee to provide a sufficient standard upon which to render a decision.

10.5.3 Reliability Standards and Operating Standards. Existing published reliability criteria, standards and guidelines of the Western Systems Coordinating Council and the National Electric Reliability Council shall be deemed to be consistent with Prudent Utility Practice. The utility criteria, standards, and guidelines of a Member utility, which were published as of January 1, 1992, shall be rebuttably presumed to be consistent with Prudent Utility Practice. Charges to such Member utility criteria, standards or guidelines shall be subject to the Dispute Resolution Procedure on the grounds of inconsistency with Prudent Utility Practice or that they are inconsistently applied as to the Member's own expected uses or similar expected uses of other Members. Where no published criteria, standards or guidelines exist, any decision related to reliability or to system operations is subject to the Dispute Resolution Procedure on the grounds of inconsistency with Prudent Utility Practices.

10.5.4 Panel Unable to Adopt Position. To the extent that the Panel finds it cannot adopt the position of one or all the Parties because the position(s) does not conform with the

applicable law or these Bylaws, the Panel may elect either to: (i) issue a final decision adopting a position of a Party which does conform to the law or these Bylaws; or (ii) notify the Parties of its ruling as to the law or Bylaw provisions at issue and allow them to submit revised positions conforming to such ruling.

10.5.5 Interpretation of Bylaws. In arriving at a decision, the Panel must necessarily interpret and construe these Bylaws; however, nothing contained in this Section 10.5 shall be deemed to permit the Panel to waive or change any of the express provisions of these Bylaws, including this Section 4 and its subsections.

10.5.6 Dispute Resolution Procedure Binding on Parties. The panel's decision shall be in writing, and shall state the grounds for its decision. Except as provided in Section 10.6, the decision of the panel shall be binding upon all parties to the Dispute Resolution Proceeding, including Indispensable Intervenors and parties which forfeited their respective rights pursuant to Section 10.3.2.

10.5.7 No Compensatory Damages Through Dispute Resolution Procedure. Compensatory damages shall not be awarded by the Panel in any Dispute Resolution Proceeding decision. These Bylaws shall restrict no Member from seeking judicial redress of any alleged compensatory damages with respect to any matters relating to these Bylaws.

10.6 **Limited Appeal to FERC.** Any Party to the Dispute Resolution Process may appeal to FERC any award rendered pursuant to this Section 10 only upon the grounds that the award is contrary to, or beyond the scope of, these Bylaws or is inconsistent with any then applicable FERC certification order with respect to these Bylaws, or is unjust, unreasonable, unduly discriminatory or preferential. **[This standard of appeal is based upon the consensus language. This is acceptable if FERC adopts the provision in the consensus language indicating that awards will be "accorded substantial deference" by FERC.]**

10.7 Compliance Schedule. A schedule for compliance shall be set forth in the Panel's decision, or, in the alternative, shall be determined as follows.

10.7.1 Mutually Agree to Schedule. The Parties shall meet and confer in good faith to agree upon a compliance schedule within seven calendar days of the Panel's decision (days one through seven); .

10.7.2 Submit Proposed Schedule to Panel. If the Parties fail to agree within this initial seven-day period (days one through seven), each Party shall then submit a proposed compliance schedule to the Panel within the next seven calendar days (days eight through fourteen).

10.7.3 Panel Selects Schedule. The Panel shall select one of the proposed compliance schedules within seven calendar days thereafter (days fifteen through twenty-one).

10.7.4 Parties Comply with Schedule. Subject to Section 10.9, the Parties shall take whatever action is required to comply with the Panel's decision and the compliance schedule.

10.8 Costs of Dispute Resolution Procedure. Each party shall bear its own costs, including attorneys fees, associated with the Dispute Resolution Proceeding and preparation thereof. All expenses directly related to the Dispute Resolution Proceeding (e.g. arbitrators' fees, court reporters fees) shall be borne by the losing Party or Parties (as determined by the Panel), unless the Parties agree to an alternate method of allocating costs.

10.9 Regulatory Approval. Except as otherwise provided in Sections 5.4 and 10.6, to the extent the decision requires or involves regulatory action, all Parties and Indispensable Intervenors to the Dispute Resolution Proceeding shall submit and fully support the Dispute Resolution Proceeding decision before the appropriate Regulatory Authority. However, Members shall be relieved of their obligations to comply with the Dispute Resolution Proceeding decision and the compliance schedule in the event that the legally required approval of a Regulatory Authority is denied, or in the event that the Regulatory Authority denies the requested ratemaking treatment such that the Member is prevented from

recovering prudently incurred costs required in implementing the Dispute Resolution Proceeding decision. Members that fail to obtain regulatory or other agency approval of the Dispute Resolution Proceeding decision are subject to the expulsion provision of Section 3.1.C.

10.10 Enforcement of Dispute Resolution Proceeding Decision. The decision of the Panel may be enforced by any court or agency having jurisdiction over the Party against which the decision is rendered.

10.11 Extension of Time Periods By Mutual Agreement. Any of the time periods provided in this Article 10 may be extended by mutual agreement of the Initiating Party, the Respondent, and any Indispensable Intervenors, with the approval of the Panel (if a Panel has been selected).

10.12 Settlement of Dispute During Dispute Resolution Proceeding. A dispute may be settled at any time during the Dispute Resolution Process, in part or in whole, by and between any of the Initiating Parties and any or all of the Respondents and/or Intervenors. To the extent reasonably possible, the settling parties should attempt to include all affected parties in the settlement. Upon reaching a settlement, the settling members of the Initiating Party shall promptly advise the Panel and the Board or Board-appointed subcommittee, and shall file a copy of the settlement with those bodies. Non-settling members of the Initiating Party shall be unaffected by the settlement, and may proceed against the Respondents and Intervenors as if no settlement had taken place, provided that the Panel may conduct a prehearing conference to consider the status of remaining issues and may allow the remaining parties the opportunity to amend their Proposals as is appropriate.

10.13 Dispute Resolution Procedure Subject to Section 5.4 - To the extent the provisions of Section 10 are inconsistent with the provisions of Section 5.4, the provisions of Section 5.4 shall prevail.

11. FAILURE TO DISCHARGE OBLIGATIONS; SPECIFIC PERFORMANCE REMEDY:

11.1 Failure to Discharge Obligations Under These Bylaws. Except as otherwise determined by the Board of Directors, any Member which shall breach any of its duties or obligations under these Bylaws, following notice thereof and a reasonable time to cure such breach, shall not be entitled (i) to receive any information, data or plans as set forth in Section 4, (ii) to access to the repository

established pursuant to Section 4.5, (iii) to request transmission service pursuant to Section 5 and the applicable Appendix A, or (iv) to vote with respect to any matter before the Planning Committee or the Board of Directors. Any member who is accused of a breach of any of its duties or obligations under these Bylaws shall not be entitled to vote on whether it has so breached or on the issuance of the notice of such breach.

11.2 **Specific Performance.** In the event a Member files a legal action against another Member for breach of a duty or obligation arising under Section 4, it is agreed that a court may, as a nonexclusive remedy and in addition to any other remedy available in law or equity, order such Member to specifically perform such obligation or duty.

12. GENERAL PROVISIONS:

12.1 **Governing Law.** These Bylaws shall be interpreted, governed by and construed under the laws of the State of California or the laws of the United States, as applicable, as if executed and to be performed wholly within the State of California.

12.2 **Construction of Agreement.** Ambiguities or uncertainties in the wording of these Bylaws shall be construed in a manner that most accurately reflects the intent of the Members when WATSCO was formed and is consistent with the nature of the rights and obligations of Members with respect to the matter being construed. These Bylaws are the result of negotiations between the Members and, accordingly, shall not be construed for or against any Member regardless of which entity drafted these Bylaws or any portion thereof.

12.3 **Uncontrollable Forces.** No Member shall be considered in default in the performance of its obligations under the Bylaws (other than obligations of a Member to pay costs and expenses) when a failure of performance shall be due to an Uncontrollable Force. A Member rendered unable to fulfill any of its obligations under the Bylaws by reason of an Uncontrollable Force shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein shall be construed so as to require a Member to settle any strike or labor dispute in which it is involved.

12.4 **Execution by Counterparts.** These Bylaws may be execute in any number of counterparts, and upon execution by the

initial Members, each executed counterpart shall have the same force and effect as an original instrument and as if all initial Members had signed the same instrument. Any signature page of the Bylaws may be detached from any counterpart of the Bylaws without impairing the legal effect on any signatories thereon, and may be attached to another counterpart of the Bylaws identical in form hereto but having attached to it one or more signature pages.

12.5 Section Headings. Section headings are for convenience and not to be construed as interpretation of text.

12.6 Previous Communications. These Bylaws contain the entire agreement and understanding between Members as to the subject matter of the Bylaws and supersede all prior commitments, representations and discussions between Members with respect to such Bylaws.

12.7 Signature Clause. The signatories hereto represent that the have been appropriately authorized to enter into these Bylaws on behalf of the Member for whom they sign. Each signatory to these Bylaws represent that the entity for which they represent has the requisite power and authority to enter into these Bylaws.

THESE BYLAWS shall be effective as of the _____ day of _____, 1993.

[SIGNATURE BLOCKS]

APPENDIX A - STATE OF CALIFORNIA

TRANSMISSION SERVICE REQUEST PROCESS AND PRIORITY

Except as otherwise provided in this Appendix A, if a term that is defined in the WATSCO Bylaws is used in this Appendix A, said term shall have the same definition in Appendix A as provided in the WATSCO Bylaws.

I. Transmission Service Request Process

A. Transmission Service. The following process shall apply to requests for transmission service under Section 5.1 of the Bylaws:

1. Notice Date. The Member to whom the request is directed (hereinafter "Transmission Provider") shall immediately "date stamp" each such request upon its receipt, which shall constitute the Notice Date. The Transmission Provider shall promptly notify the Planning Committee of the request.

2. Initial Response. Within fifteen calendar days from the Notice Date of Section 5.1, the Transmission Provider shall notify the requesting Member (hereinafter "Transmission Requester") in writing if there is insufficient information in the request, and what additional information is needed. Upon receipt of such notice of insufficiency, the Transmission Requester shall have fifteen (15) calendar days thereafter to provide the Transmission Provider with the additional information. If the Transmission Requester fails to provide the additional information to the Transmission Provider within the fifteen-day period, the Transmission Requester's request shall be deemed null and void for priority purposes under Section III. The Transmission Requester may at any time thereafter submit a new request to the Transmission Provider that contains sufficient information, which shall be time date stamped by the Transmission Provider with a new Notice Date.

Within fifteen (15) days from the Notice Date or, in the event insufficient information is provided in the request, within fifteen (15) days of the date the Transmission Provider receives a request with sufficient information, the Transmission Provider shall notify the Transmission Requester: a) whether the requested service is partially or wholly available without further study (assuming the Transmission

Provider is reasonably able to make such a determination); b) whether a forty-five day study will be required to determine the availability of the requested service or the need, if any, for the construction of Incremental Additions, and the cost of such forty-five day study; or, c) that the requested service is unavailable due to a pending request by another Transmission Requester.

3. Availability of Requested Service after Fifteen Day Study. If the Transmission Provider notifies the Transmission Requester after a fifteen (15) day study that the requested service is partially or wholly available, the Transmission Requester shall notify the Transmission Provider in writing of its decision to accept service, subject to entering into a mutually agreeable transmission service contract. The Transmission Requester's acceptance notice shall be delivered to the Transmission Provider no more than thirty (30) calendar days from the date it receives the Transmission Provider's notice under Section I(A.2).

The acceptance notice shall state whether the Transmission Requester is accepting: i) the full amount of requested transmission service, which is wholly available; ii) less than the full amount of requested transmission service, which is partially available; or, iii) less than the full amount of the requested transmission service, which is partially available, but the Transmission Requester continues to request the remaining amount of desired transmission service (which may require Incremental Additions, pending further study).

The Transmission Requester and the Transmission Provider shall have a maximum of six (6) months from the delivery of the acceptance notice to negotiate in good faith a transmission service contract.

If the Transmission Requester fails to provide its written acceptance notice to the Transmission Provider within the thirty-day period, the Transmission Provider's obligation to provide the requested service is discharged. The Transmission Requester shall then have the right to resubmit its request for that service pursuant to Section 5.1 of the Bylaws.

4. Further Study Required. If the forty-five day study described in Section I(A.2) is required, the Transmission Requester shall provide written notice to the Transmission Provider of its decision to proceed within fifteen (15) calendar days of the date it

receives the Transmission Provider's notice under I(A.2). If the Transmission Requester fails to provide its written notice within the fifteen-day period, the Transmission Provider's obligation to conduct the study or provide the requested service is discharged. The Transmission Requester shall then have the right to resubmit its request for that service pursuant to Section 5.1.

5. Forty-Five Day Study. After receipt of the Transmission Requester's notice to proceed with a forty-five day study, the Transmission Provider and the Transmission Requester shall, within fifteen (15) calendar days thereafter, agree upon any additional information and the assumptions that are reasonably necessary to conduct the study. The Transmission Provider shall commence the forty-five day study upon receipt of both the necessary information to conduct the study and the executed agreement for payment, if required, for the study pursuant to Section II of this request process.

Upon completion of the forty-five day study, the Transmission Provider shall notify the Transmission Requester in writing whether: (a) the requested service is partially or wholly available without further study; or, (b) Incremental Additions are necessary to provide the requested service. As part of the notice, the Transmission Provider shall also provide to the Transmission Requester the available transmission studies (including the underlying assumptions) which serve as the basis for the Transmission Provider's conclusion(s) regarding the availability of transmission service or the need for Incremental Additions.

If Incremental Additions are necessary to provide the requested service, the Transmission Provider's notice shall specify whether an engineering-economic study of construction alternatives is required. The Transmission Provider may require up to ten (10) months to conduct that study. If an engineering-economic study is required, the Transmission Provider's notice shall also specify the cost of that study.

6. Availability of Requested Service after Forty-Five Day Study. If the Transmission Provider's notice after the forty-five day study indicates the requested service is partially or wholly available, the Transmission Requester shall notify the Transmission

Provider of its decision to accept the service, subject to entering into a mutually agreeable transmission service contract. The Transmission Requester's acceptance notice shall be delivered to the Transmission Provider no more than thirty (30) calendar days from the date it receives the Transmission Provider's notice of availability under Section I(A.5). The Transmission Requester and the Transmission Provider shall have a maximum of six (6) months from the delivery of the acceptance notice to negotiate in good faith a transmission service contract.

The acceptance notice shall state whether the Transmission Requester is accepting: i) the full amount of requested transmission service, which is wholly available; ii) less than the full amount of requested transmission service, which is partially available; or, iii) less than the full amount of the requested transmission service, which is partially available, but continues to request the remaining amount of desired transmission service (which will require Incremental Additions - see Section I(A.7)).

If the Transmission Requester fails to provide its written acceptance notice within the thirty-day period, the Transmission Provider's obligation to provide the requested service is discharged. The Transmission Requester shall then have the right to resubmit its request for that service pursuant to Section 5.1, provided that the Transmission Provider shall, to the extent possible, use its previous studies and avoid duplicating costs in responding to the resubmitted request.

7. Request For Further Study of Incremental Additions. If the Transmission Requester decides to proceed with the engineering-economic study described in Section I (A.5), the Transmission Requester shall provide written notice to the Transmission Provider within thirty (30) calendar days of receipt of the Transmission Provider's notice under Section I(A.5). If the Transmission Requester fails to provide its written notice within the thirty-day period, the Transmission Provider's obligation to provide the requested service is discharged. The Transmission Requester shall then have the right to resubmit its request for that service pursuant to Section 5.1, provided that the Transmission Provider shall, to the extent possible, use its previous studies and avoid duplicating costs in responding to the resubmitted request.

8. Further Study of Incremental Additions. After receipt of the Transmission Requester's notice requesting the study of construction alternatives, the Transmission Provider shall immediately provide notice of such request to the Planning Committee pursuant to Section III(B.2). After the thirty (30) day notice period of Section III(B.4) has expired, the Transmission Provider, the original Transmission Requester, and any other Member requesting transmission service pursuant to Section III(B.4), shall, within fifteen (15) days thereafter, agree upon: (a) any additional information and the assumptions that are reasonably necessary to conduct the study, and (b) the schedule for completing the study, which shall not exceed ten (10) months except upon mutual agreement. The Transmission Provider shall determine the cost of such study and advise all interested parties.

The Transmission Provider shall commence the study upon receipt of both the necessary information to conduct the study and the Transmission Requesters' payments, if any, for the study that are due pursuant to Section II.

Upon completion of the study, the Transmission Provider shall notify the Transmission Requester(s) in writing, and shall provide the following information: (a) the alternatives studied; (b) the preliminary estimated cost of constructing those alternatives; (c) the rationale for the selection of the preferred alternative; and, (d) the proposed allocation of costs for the preferred alternative.

9. Notice of Desire to Pursue Construction. If the Transmission Requester(s) desire(s) to pursue construction of the preferred alternative, each Transmission Requester shall provide written notice to this effect to the Transmission Provider within sixty (60) calendar days of the date it receives the Transmission Provider's notice under Section I(A.8) above.

If the Transmission Requester fails to provide written notice within the sixty-day period, the Transmission Provider's obligation to construct is discharged. The Transmission Requester shall then have the right to resubmit its request for that service pursuant to Section 5.1, provided that the Transmission Provider shall, to the extent possible, use its previous studies and avoid duplicating costs in responding to the resubmitted request.

10. Obtaining Permits and Approvals; Compliance with CEQA. After receipt of each Transmission Requester's notice of desire to pursue construction of the preferred alternative under Section I(A.9), the Transmission Requester(s) and the Transmission Provider shall agree upon the necessary steps to comply with California Environmental Quality Act, and the permits and approvals, if any, which should be obtained prior to a commitment to construct the preferred alternative. Upon completion of these tasks, the Transmission Requester(s) shall provide to the Transmission Provider written notice to proceed with construction of the preferred alternative within sixty (60) calendar days of completion of such tasks.

11. Agreement for Construction. After receipt of the notice(s) of the Transmission Requester(s) to proceed with construction under Section I(A.10) above, the Transmission Requester(s) and the Transmission Provider shall agree upon: (a) the schedule for the detailed engineering design and cost estimate, regulatory filing (if applicable), additional environmental compliance (if necessary), and the estimated construction period; and, (b) each Transmission Requester's allocated share of costs for the detailed engineering design, licensing, and construction.

The Transmission Provider shall commence work (and the schedule shall begin) when the Transmission Provider receives all Transmission Requesters' payments that are due in accordance with Section II. The Transmission Provider shall make a good faith effort to complete the detailed engineering design and construction, obtain all necessary regulatory approvals, and place the project in service in a timely manner after it receives the Transmission Requesters' payments that are due in accordance with Section II.

B. Time Periods.

Notwithstanding the maximum time periods as provided in Section I (A.) above, the parties shall make a good faith attempt to perform their respective obligations as expeditiously as possible. The existence of such maximum time periods shall not excuse Members from making a good faith effort to complete their respective obligations in less time. Any of the time periods provided in Section I(A.), however, may, for good cause, be extended by mutual agreement of the Transmission Requester(s) and the Transmission Provider, provided that the extension shall not unduly delay or otherwise prejudice a competing Member's request. The Transmission Provider shall notify Members with competing requests of the proposed extension, and the reason(s) therefor

Each competing Member shall be allowed seven (7) calendar days from receipt of the Transmission Provider's notice to determine whether its request may be unduly delayed or prejudiced by the proposed extension. If a Member with a competing request notifies the Transmission Provider in writing that the extension would likely cause the Member's request to be unduly delayed or prejudiced, then the written consent of the competing Member to the proposed extension shall be required. The competing Member's written consent, however, shall not be unreasonably withheld.

Transmission Requester(s) shall grant reasonable extensions to the Transmission Provider to allow for the study of additional transmission requests from other Members under Section III and I(A.8) or for the study of concurrent requests of a Transmission Requester.

II. Transmission Study Costs

The Transmission Provider may, at its option, require the Transmission Requester to compensate it for all or part of the reasonable costs of any study required of the Transmission Provider pursuant to Section I above. Such reasonable costs shall be limited to costs that are directly related to the performance of the study, and shall not include costs that are incurred by the Transmission Provider prior to the study request. If the Transmission Provider requires payment for such studies, it shall undertake such studies upon written agreement by the Transmission Requester to pay the required amount.

III. Priority of Requests for Transmission Service

A. Available Transmission Capacity. Available Transmission Capacity shall be made available to the Member whose written transmission request is received first in time by the Transmission Provider, provided that the Transmission Requester and Transmission Provider enter into a transmission service contract for the Available Transmission Capacity within six (6) months of the written acceptance date of Section I(A.3) or I(A.6), as is applicable. The six (6) month period shall be automatically tolled in the event of a dispute resolution filing by either Member concerning such request or in the event of delay caused by Uncontrollable Force. The Transmission Requester and the Transmission Provider may also extend such six (6) month period by mutual agreement under Section I(B.) above.

The six (6) month negotiating period is a maximum period, and shall not excuse the Transmission Requester and the Transmission Provider from negotiating in good faith a transmission service contract in less than six months.

If the Transmission Requester fails to enter into a transmission service contract within the six (6) month period (unless said

period is extended by mutual agreement or due to Uncontrollable Force or is tolled by a dispute resolution filing), then the Transmission Provider shall offer the Available Transmission Capacity to the next request in time, and so on. Nothing herein shall prohibit the submission of joint transmission requests.

B. Incremental Additions Required. In the event that a Transmission Provider determines, in response to a Member request pursuant to Section 5.1 above, that no or inadequate Available Transmission Capacity exists to meet the Member's request and that Incremental Additions will be necessary to provide the requested transmission service, then the following shall apply:

1. The Transmission Provider shall notify the Transmission Requester in writing of its determination of the need for Incremental Additions (see Section I(A.5.b.).

2. At the same time as the notification of 1. above, the Transmission Provider shall also notify the WATSCO Planning Committee. The Planning Committee, or its designee, shall notify all WATSCO Members of the Transmission Provider's determination of the need for Incremental Additions (see Section I(A.8).

3. The notice shall contain, at a minimum: a copy of the transmission service request; the location of the transmission path; a description of the existing transmission facilities; the estimated Incremental Additions that would be necessary to accommodate the transmission service request based on information supplied pursuant to Section 5.1 of the Bylaws and any other likely future forecasted transmission requirements over that path; and the estimated Costs of such Incremental Additions.

4. Any Member may, within thirty (30) days of the date of the Incremental Addition notice of Section III(B.2), submit a request for transmission service to the Transmission Provider over the same transmission path requiring Incremental Additions (see Section I(A.8).

5. All Members providing a notice under Section III (B.4) above shall be entitled to participate, on a pro rata basis (based on their written transmission service requests), in future transmission studies pursuant to Section I(A.8) and ultimately in a project agreement that reflects the rights and obligations of the transmission project participants in accordance with Section 5.3 of the Bylaws.

Nothing herein, however, prohibits the participating Members from agreeing to participation shares on other than a pro rata basis.

6. In the event additional request(s) are submitted pursuant to Section III(B.4), the Member submitting the original request ("original Transmission Requester") shall have the option of participating or not participating in future transmission studies that may lead to a project agreement described in Section III(B.5). An original Transmission Requester shall exercise its option within thirty (30) days following the expiration of the thirty (30) day request period of Section III(B.4), including any extension thereof. An original Transmission Requester choosing to participate in a Section III(B.5) transmission study shall have the same rights and obligations as any other Member participating in that study pursuant to Section III(B.5).

If the original Transmission Requester chooses not to participate in the Section III(B.5) transmission study, said Member shall nevertheless be entitled to proceed as if no other Members had submitted notices pursuant to Section III(B.4). In particular, the original Transmission Requester shall be entitled to request an independent study based on the original transmission service request, which request shall be made within thirty (30) days following the expiration of the thirty (30) day request period of Section III(B.4), including any extension thereof.

In the event the Transmission Provider undertakes a transmission study under Section III(B.5) and also performs an independent transmission study for the original Transmission Requester, the Transmission Provider shall include the transmission service request of the original Transmission Requester in the Section III(B.5) study. If the Section III(B.5) study results in a project agreement, the original Transmission Requester shall be entitled to the same service, at the same costs, as identified in the independent study performed for the original Transmission Requester.

C. Member-Initiated Transmission Improvements. If a Member initiates a project improving its transmission facilities at 50 kV or above, which results in an increase of transmission capacity, then the following shall apply:

1. The initiating Member shall notify the WATSCO Planning Committee. The Planning Committee, or its designee, shall notify all WATSCO Members of the initiating Member's intent to plan and construct such improvements.

2. The notice shall contain, at a minimum: the location of the transmission path; a description of the existing facilities; the estimated transmission improvements that would be necessary to accommodate the forecasted transmission requirements over that path; and the estimated costs of such transmission improvements.

3. Any Member may, within thirty (30) days of the date of the transmission improvement notice of Section III(C.1), submit a request for transmission service to the initiating Member over the same transmission path requiring transmission improvements.

4. All Members providing a notice under Section III (C.3) above shall be entitled to participate, on a pro rata basis (based on their written transmission requests), in a project agreement that reflects the rights and obligations of the transmission project participants in accordance with Section 5.3 of the Bylaws, provided that the initiating Member's transmission requirements are met first from the lowest cost incremental addition of the transmission improvements, and the initiating Member is compensated by the participating Members for: i) any additional costs associated with the participating Members' participation in the transmission project; and, ii) the participating Members' pro rata share of the project's development costs to date.

D. Competitive Bidding Process of Member. It is understood that Members may from time to time engage in a competitive bidding process for resource acquisition. In such event, the following principles shall apply:

1. Commencing at a reasonable time prior to the publishing of the request for proposal (RFP), the bid-conducting Member shall be entitled to set aside for its own resource needs that amount of Available Transmission Capacity that is equal to its total resource solicitation. The bid-conducting Member may set aside that amount of Available Transmission Capacity, on a system-wide basis, until such time as it determines with reasonable certainty the amount and location of transmission capacity that is not needed to accommodate potential winning bids for its own resource solicitation needs.

2. Following receipt of the responsive bids, the bid-conducting Member shall have an on-going obligation, in response to a Member's transmission request, to determine the existence of any Available Transmission Capacity of the bid-conducting Member. The bid-conducting Member shall base

its on-going determination upon the best available information regarding the potential winning bids and their likely effect on the bid-conducting Member's Available Transmission Capacity.

3. A wheeling Member shall provide Available Transmission Capacity to Transmission Requesters on a first in time basis in accordance with Section III(A.). For purposes of a competitive bidding process, a written request by the bid-conducting Member to a wheeling Member for a wheeling study regarding an out-of-area bid shall be deemed a written transmission request under Section III(A.) as of the date the written wheeling study request is received by the wheeling Member (which is the Notice Date). The priority afforded such Notice Date under Section III(A.), however, shall be lost if an award of said bid is not made within a reasonable period of time from the date the bid-conducting Member receives the results of the written wheeling study by the wheeling Member.

The Planning Committee may adopt rules and guidelines, including guidelines for determining reasonable time periods in Section III (D.1 and 2) above, to implement the foregoing principles.

E. Bad Faith. A Transmission Provider may not refuse to respond to a Member's transmission request under Section 5.1 of the Bylaws and this Appendix A on the basis that, in the Transmission Provider's opinion, the Transmission Requester does not need or require the requested transmission service. Likewise, a Transmission Requester may not make a transmission service request under Section 5.1 of the Bylaws and this Appendix A in bad faith, i.e., without a reasonable expectation of utilizing the transmission service if the request is granted. A Member that makes a bad faith transmission service request or in bad faith refuses to respond to a request for transmission service may be subject to disciplinary action under Section 8.4.1 of the Bylaws, as well as any other legal recourse that an aggrieved Member may have against such offending Member.

F. Substantial Change to Transmission Request/Loss of Priority. In the event that a Transmission Requester unilaterally makes a substantial change to a transmission service request submitted under Section 5.1 of the Bylaws and this Appendix A, said revised request shall lose its Notice Date under Section III above (and the resulting priority), and shall be deemed a new request as of the date that the Transmission Provider receives the Transmission Requester's written request to substantially revise the original request. The Planning Committee may adopt rules and guidelines regarding what constitutes a "substantial change" to a transmission service request.

IV. Miscellaneous

A. Notice of WATSCO Agreements to Planning Committee. Members are encouraged to notify other Members or entities likely affected by the implementation or operation of proposed agreements under WATSCO. To facilitate openness and trust among Members, each Member shall ensure the Planning Committee receives a copy of each WATSCO agreement that is entered into, within seven (7) days of execution of the agreement. The Planning Committee shall adopt reasonable rules and guidelines for notifying other Members of such WATSCO agreements.

The notice requirements of this Section IV A., or under the rules and guidelines adopted by the Planning Committee pursuant to this section, shall not be deemed to establish a legal or equitable duty or obligation on the part of a Member to notify another Member or non-Member under this section, nor shall any non-Member be deemed a third party beneficiary as a result of this section.

B. Notice/Computation of Time. Except as otherwise provided by the Planning Committee, or by mutual written agreement of all affected Members, Members shall provide all notices required under Appendix A in writing, and shall cause such notices to be delivered by courier service or by certified mail, return receipt requested, to the appropriate party at the address designated by such party.

For purposes of computing any time or notice period of Appendix A, the period shall be so computed as to exclude the first day and include the last day; provided, that when the last day of any such period falls on Saturday, Sunday or a holiday under the laws of California, the computation shall omit such day and include the first business day thereafter.

APPENDIX B

WATSCO MEMBERSHIP

3/31/93 (Final text subject to approval by all parties.)

EXHIBIT A

LONG TERM TRANSMISSION PLAN
FOR
STATE OF CALIFORNIA

RECEIVED
OCT 14 1993
WIEB

12/16/91

ELECTRIC TRANSMISSION SERVICE POLICY STATEMENT

Following are the conditions for transmission service provided by Public Service Company of Colorado (Public Service) and Tri-State Generation and Transmission Association (Tri-State) applicable to their bulk transmission systems. Public Service and Tri-State jointly are referred to as Both Parties. Both Parties anticipate acquiring various portions of the transmission assets previously owned by Colorado-Ute Electric Association. A portion of those facilities will be owned and operated jointly. This Transmission Service Policy Statement provides for requests by third parties, for use of these jointly-owned facilities as well as use of Both Parties' other transmission facilities, to be treated under similar terms and conditions.

Both Parties are cognizant of the regulatory trend to condition any approvals of electric utility mergers and acquisitions on transmission access as a means of mitigating monopoly power of transmission owners. Both Parties have always been willing to provide transmission service for third parties.

1. Coordinated Planning

Both Parties are strong advocates of the "single-system" planning concept. For the purposes hereunder "single-system" planning shall mean the planning necessary to most efficiently utilize the

existing transmission system and make the appropriate additions, upgrades and enhancements to the system as if they were owned by a single entity and includes evaluation of both technical and economic factors. Both Parties believe that major additions to the regional transmission system should be planned jointly and that all affected participants are entitled to an opportunity to invest or otherwise responsibly share in the benefits and the costs of system enhancements associated with new generation and transmission additions.

The Parties will work with and encourage all utilities, irrespective of size or ownership, to plan transmission additions and access on a "single-system basis" to minimize duplication of facilities and costs.

Both Parties have developed strong working relationships and effective joint-planning processes with the power supply organizations and electric utilities in Wyoming, Colorado, and Nebraska, including, among others, members of the Western Systems Coordinating Council, the Inland Power Pool and the Rocky Mountain Power Pool.

2. OFFER OF SERVICE

Both Parties will provide firm and non-firm transmission service over their bulk transmission systems, at voltages of 69KV and above to any requesting electric utility or any requesting non-utility electric power supplier for specified transmission service deliveries of wholesale power and energy to an electric utility.

For those utilities which are not interconnected with the Parties at voltages at 69KV and above, the Parties will utilize their best efforts to cause to be provided the transformation and/or other facilities necessary to form an interconnection and to effect the requested transmission service according to the procedures described in Article (3) hereof. Transmission service provided pursuant to this Statement shall be subject to (i) the engineering and reliability limitations of the bulk transmission system as determined using standard utility practices in the planning concept described in Article (1) above, (ii) the obligations of Both Parties to provide firm service, including future growth considerations, to their existing and new retail and existing wholesale native load customers and (iii) the obligations of one or Both Parties under previously executed contracts to provide firm transmission and firm bulk power services. If those limitations, determined in accordance with the procedures in Article (3) hereof, mean that either Public Service or Tri-State must add or upgrade facilities to perform the requested transmission service, facilities sufficient to meet the request as described below will be added or upgraded.

A utility, or its wholesale power supplier, receiving transmission service from one or Both Parties must meet the applicable Reliability Criteria for System Design, the Minimum Operating Reliability Criteria and adhere to the Operating Procedures set forth by the Western Systems Coordinating Council (WSCC) for deliveries in that Council area, or the Mid-Continent Area Power Pool (MAPP), for deliveries east of the western U.S.-central U.S.

synchronous electrical separation. These criteria may be met singularly or through a reserve pool such as the Inland Power Pool or the Colorado Power Pool, by installing load shedding equipment approved by the control area operator or through contractual arrangements approved by the control area operator.

3. PROCEDURES FOR REQUESTS REQUIRING ADDITIONAL FACILITIES

Within 60 days of receiving a written request from an electric utility or a non-utility electric power supplier for transmission service, one or Both Parties, depending on the nature of the request, will determine whether sufficient transmission capacity exists and will inform the requestor of that determination. To the extent that additions to the transmission facilities of one or Both Parties are necessary to provide firm transmission service, and are feasible to construct within the desired time frame of the requestor, one or Both Parties will inform the requestor of the time necessary to conduct appropriate study(ies) of the facility addition(s) required to provide the requested transmission service. One or Both Parties will plan jointly with affected utilities to determine the optimum solution based on the "single-system" planning concept.

The requestor must agree to reimburse one or Both Parties for the cost of this study except that, to the extent one or Both Parties plan to participate in the additional capacity to be provided by the requested facility addition, then it or they shall bear a proportionate cost of the study. The facility study will include a description of the new facilities required, an estimate of the

cost of the additions, the extent to which one or Both Parties desire to participate in the ownership or capacity rights of the facility, an estimate of the costs and charges which would be assigned to the requesting party, the contract term required to support the economic requirements of the new facilities, and an estimate of the time required to design and construct the new facilities and initiate the requested service.

After reviewing the facility study(ies), if the requestor wishes either or Both Parties to proceed with the design and construction of the additional facilities, the requestor must enter into a transmission service agreement with one or Both Parties. That agreement shall include the contractual arrangements necessary for the design, construction and operation of the additional facilities and shall obligate the requestor to pay for the appropriate costs, including the ongoing ownership costs, associated with such design and construction of the facilities and associated services provided. One or Both Parties will then use due diligence to complete the new facilities and initiate the requested service.

The requestor will provide such assistance, in good faith, as may be required to obtain all necessary permits, approvals and rights-of-way for such construction. If one or Both Parties are not able to obtain such permits, approvals and/or rights-of-way within 30 months (or as otherwise may be mutually agreed) of initiating proceedings therefor in good faith, one or Both Parties will have no further obligation to the requestor. The requestor's obligation to one or Both Parties shall be as provided for in the transmission

service agreement. If one or Both Parties and the requestor are unable to agree upon a reasonable time to construct any new facilities determined by one or Both Parties to be necessary to provide the requested service, or if either party believes the other party has not acted in good faith or has failed to proceed with due diligence toward the construction of new facilities in this process, then either party may submit the dispute to arbitration in accordance with procedures to be filed with the Federal Energy Regulatory Commission (FERC) for Public Service and in accordance with the procedure attached to this Statement (Attachment A) for Tri-State.

4. RATES FOR SERVICE

The rates for firm and non-firm transmission services provided by Public Service shall be the applicable rates on file and in effect from time to time with the FERC. Where the transmission service provided requires Public Service to own or install new facilities or incur additional expenses attributable only to the particular service provided, a pro rata share of Public Service's investment in these new facilities and of the associated additional expenses will be specifically assigned to the transmission service customer based on that customer's requirements and such share shall be reflected in additional monthly charges to that customer, taking into account revenue requirement factors approved in the Company's latest FERC rate proceeding. The costs associated with any investment in facilities or expenses which are specifically assigned to a transmission service customer shall be segregated from other system costs and shall not be reflected in the base

transmission service rate which that customer shall be charged for use of the transmission system.

Tri-State will offer transmission services on a cost basis which considers all transmission-related costs, including appropriate overheads and return on capital, in the Tri-State system divided by all uses of the Tri-State system and the appropriate share of new construction or facility costs on a ratio of benefits received from required additions.

For transmission services provided in facilities owned jointly by Both Parties, a requestor of such services may contract with either Tri-State or Public Service for use of that owner's available rights in the facility at that owner's transmission service tariff. The requestor may divide the requested service between Both Parties using the applicable tariff for the desired use of each owner's rights.

5. USE OF OTHER TRANSMISSION SYSTEMS

If the requested transmission service involves transmission directly or indirectly on the facilities of another utility system, the requestor shall make arrangements for use of those facilities directly with that utility system, and neither of Both Parties shall be obliged to commence construction or transmission service until such arrangements have been made.

6. TERMS FOR CONTRACTED SERVICE

Both Parties will agree to contract to provide long-term, firm transmission service on a reserved capacity basis for terms of up to 20 years, as requested by the transmission service customer. The term for non-firm transmission service may be as short as one hour.

7. SERVICE AGREEMENTS

Public Service is obligated to provide transmission service under this Statement only to utilities and non-utility electric power suppliers that have signed a transmission service agreement with Public Service for the requested service. Such agreement shall be filed with the FERC and subject to that Commission's approval. The transmission service agreement shall contain a statement of service specifications including, without limitation, the amount of capacity reserved for transmission service; the type of service(s) provided; the term of such service; identification of point(s) of receipt, point(s) of delivery, and delivering or receiving parties; and the tariffs applicable to such service.

Tri-State is obligated to provide transmission service under this Statement only to utilities and non-utility electric power suppliers that have signed a transmission service agreement with Tri-State for the requested service. The transmission service agreement shall contain a statement of service specifications including, without limitation, the amount of capacity reserved for transmission service; the type of service(s) provided; the term of such service; identification of point(s) of receipt, point(s) of

delivery, and delivering or receiving parties; and the tariffs applicable to such service.

Attachment A

ARBITRATION

It is the intent of the Parties to in good faith resolve all disputes arising out of the performance of the terms and conditions of this policy statement.

If the Party(ies) and the entity requesting transmission service, as provided herein, are unable after good faith effort to resolve any dispute, either the Party(ies) or the requesting entity may request that the disputed matter be submitted to arbitration by giving written notice to the other Party(ies) or entity that arbitration is requested. Upon the giving and receipt of such notice, the parties shall within thirty (30) days meet for the purpose of soliciting arbitrators. Each side of the dispute shall designate an arbitrator, both of whom shall be familiar with and knowledgeable about the policies and criteria of the Western Systems Coordinating Council, or its successor organization. The arbitrators so selected shall meet within twenty (20) days following this selection and shall select one (1) additional arbitrator who shall be generally familiar with the policies and criteria of the Western Systems Coordinating Council or its successor organization. If the initially chosen arbitrators are unable to agree upon a third qualified arbitrator, the Parties shall request that a judge of the United States Court of Appeals for the Tenth Circuit designate a qualified arbitrator.

At the commencement of arbitration proceedings, each party to the arbitration shall submit its written statement of position and the requested remedy or action sought to be awarded. The decision of the arbitrator shall be limited to the adoption of one of the statements of position and requested remedy or action.

Unless otherwise agreed by both parties to the arbitration, the arbitration shall be governed by the rules and practice of the American Arbitration Association (or the rules and practice of a similar organization if the American Arbitration Association should not at that time exist) from time to time in force, except that if such rules and practice shall conflict with Colorado Annotated Statutes or any other provisions of Colorado law then in force which are specifically applicable to arbitration proceedings, such law shall govern.

The Parties may elect to submit to binding arbitration. If they do so, the findings and award of the arbitrator shall be final and binding upon the Parties to the extent permitted by applicable law. Any award may be filed with the clerk of any court having jurisdiction over the Party against whom the award is rendered, and, upon such filing, such award to the extent permitted by the laws of the jurisdiction in which said award was filed, shall be specifically enforceable or shall form the basis of a declaratory judgment or other relief.

The Parties may elect to submit to non-binding arbitration. If they do so, the findings and award of the arbitrators shall not be final or binding, but such findings and award shall be admissable in any subsequent litigation concerning the dispute.

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

New Reporting Requirements To Implement Section 213(b) of the Federal Power Act and to Support Expanded Regulatory Responsibilities under the Energy Policy Act of 1992, and Other Changes to FERC Form 714	)))))	Docket No. RM93-10-000

NOTICE OF PROPOSED RULEMAKING

Western Systems Coordinating Council Comments

Western Systems Coordinating Council (WSCC) appreciates the opportunity to provide its views on the Commission's Request for Public Comments regarding the proposed new reporting requirement which informs potential transmission customers, State regulatory authorities, and the public of potentially available transmission capacity and known constraints.

Background

WSCC was formed in 1967 and is the largest of the nine regional electric reliability councils which comprise the North American Electric Reliability Council (NERC). WSCC is an international organization which promotes electric service reliability. The Council provides the forum for its Member Systems to enhance communication, coordination, and cooperation — all vital ingredients for planning and operating a reliable interconnected electric system.

The WSCC region encompasses a vast area of nearly 1.8 million square miles, representing a service area equivalent to more than one-half of the contiguous land area of the United States. It is the largest, geographically, and most diverse of the nine regional councils and its members provide substantially all of the electric service to the 59 million people in the region. WSCC's territory includes all or portions of the fourteen western states, the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California, Mexico.

Membership in WSCC is voluntary and open to all qualified electric systems within the region. WSCC's Agreement includes membership provisions for public utilities and independent power producers. WSCC's 62 Member Systems are comprised of 18 investor-owned utilities, 18 municipal utilities, 1 state agency, 17 public power systems, 4 federal agencies, 3 Canadian systems, and one Mexican system. WSCC's Affiliate Members represent one municipal utility, two public power systems, and one independent power producer.

Recognizing the changing environment in which the electric utilities now operate and the need for all players to participate in the planning process,

WSCC has taken unprecedented steps to expand and enhance the regional planning process in the West.

In 1990, WSCC revised its bylaws so that independent power producers (IPPs) may become members of WSCC. As WSCC members, IPPs have access to all of the information and data compiled by WSCC, including the power flow base case data for the WSCC region, WSCC computer programs for system analysis, WSCC transmission maps, transfer capability data, member planning criteria, NERC and WSCC planning and operating criteria/guides, and WSCC studies and surveys which evaluate system performance relative to WSCC and NERC criteria. In 1992, another proactive step was taken by the Council when it adopted a policy of making the WSCC power flow data sets available to small non-member IPPs and to regulatory agencies.

In March of 1993, WSCC adopted a regional planning process. The regional planning process is designed to provide a comprehensive and effective process focusing on: 1) facilitating the planning of multi-state and inter-utility projects having regional impact and 2) identifying opportunities to enhance interconnected system operations in the WSCC region, including the mitigation of transmission, institutional, and regulatory constraints. The establishment of regional planning guidelines and the review of regional projects relative to these guidelines will ensure that regional needs are addressed and that the full potential of regional planning opportunities will be realized.

Recognizing that the regulatory community, environmentalists, land management agencies, consumers, etc. are an integral part of regional planning, WSCC's process will include an "Outreach" program for communicating with and soliciting input and assistance from all interested stakeholders.

Regional planning is likely to involve complex, multi-state projects with many participants. WSCC's regional planning process will provide WSCC members and nonmembers with a voluntary dispute resolution service to expedite resolving both technical and nontechnical issues.

WSCC Comments on Proposed Utility Transmission Information Reporting Requirements

WSCC concurs with and supports the concept of making appropriate data and information available to all parties involved in planning and operating the interconnected electric system. In addition, WSCC concurs with and supports the concept of having regional and/or subregional organizations being the repository and distribution centers for most if not all of the information which will be reported under FERC's new Form No. 715 and the proposed reporting of hourly load data under Form 714. This approach would be the most cost effective, efficient, and coordinated way to compile and distribute this information. This concept would also reasonably ensure that the data are consistent and coordinated on a regional/subregional basis, thereby eliminating the time-consuming task of resolving the data inconsistencies which would almost certainly exist as a result of individual company reporting. The Council also agrees with the Commission's stated goal of limiting its data collection to information that is currently developed in the normal course of business and that is maintained and provided to other utilities for the purposes of coordinated regional planning. WSCC is committed to work with its members in accomplishing a reporting process that

is both efficient and will make information readily available to the appropriate parties.

In broadening and enhancing WSCC's regional planning process, the WSCC members recognize that it is very important that data availability and the WSCC regional planning process be implemented in a way which promotes joint studies and fosters communication and coordination to ensure electric system reliability. This joint study approach recognizes that it is totally impractical to attempt to provide a system data base which can be used without modification to assess any potential project someone may wish to evaluate, to assess transfer capabilities under all anticipated operating conditions, or to identify all possible system constraints. This approach also recognizes that many of the entities requesting transmission service will not have the power system background or expertise to conduct the necessary studies.

The power flow base cases compiled by WSCC reflect today's system and the system as planned each year for 10 years in the future. The base cases have been expanded to model facilities 34.5 kV and above as required by the Council for conducting regional studies. These power flow base cases may be used as a starting point for conducting screening studies. However, recognizing that these data sets only reflect a snapshot in time and do not model all of the lower voltage facilities in all areas, utilities and IPPs alike must always review and revise the data sets as required to reflect the appropriate level of detail for their particular studies. In addition, one must recognize that there are stability constraints which set the upper limits of most of the bulk power interarea transfers within WSCC.

Consequently, a joint study process is not only the most efficient and effective way to conduct planning studies, it is essential if the interconnected transmission system is to be coordinated in a way that assures system reliability and promotes regional/subregional planning. The Council therefore recommends that:

- FERC implement the data availability process in a way which promotes joint studies rather than independent studies. It is suggested that consideration be given to promoting this concept by making the required information readily available only to those entities who have a "legitimate" need for the information and have indicated a willingness to conduct joint studies with the appropriate members of the Regional Reliability Councils, RTGs, subregional planning organizations, etc., not the "general public."

The Council also recommends that:

- If the above recommendation is not adopted, the availability of system data should be limited to those entities having a "legitimate interest" in system planning which would generally, though not always, be those which qualify for transmission service under the Energy Policy Act of 1992, not the "general public." WSCC believes this approach would be in the national and public interest.

- The regional/subregional organizations compiling and making the information available be allowed to charge a reasonable fee for the information and data bases. This provision will compensate those who have compiled the information and hopefully minimize frivolous requests. The intent is not to limit access to the information, but only to ask requesters to bear their fair share of the cost of developing and providing the information.

- The reporting date for Form 715 information be in April or May to be consistent with that for FERC Form 1, FERC Form 714, and the OE-411 report annually submitted to DOE by the Regional Reliability Councils. An April or May reporting date will promote data consistency. It is also recommended that the first Form 715 report be due in April of 1995.

- FERC allow regional and subregional organizations to make a single Form 715 filing on behalf of their members which provides a summary of available information with the understanding that the required detailed information is available on request from a regional or subregional organization.

- FERC reconsider its proposal to collect hourly lambda data under Form 714. FERC has been charged with promoting competition through transmission access, and as such has the responsibility for maintaining a "level playing field." We believe the request for hourly lambda data is inappropriate as it is not being requested of all power producers and therefore may provide a competitive advantage to some power producers. It is also questionable whether this information is the appropriate data for replicating the production cost simulations as described in the proposed rulemaking.

- FERC reassess the proposed Form 715 information requirements and, based on the comments received, delete those items determined not to be

  1) readily available and developed as a normal course of business, or

  2) made available to other utilities for the purpose of coordinated regional planning.

The above comments are provided by WSCC from a regional perspective and do not imply the unanimous endorsement of its members.

WSCC would appreciate the Commission giving due consideration to the above comments and recommendations.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of:

New Reporting Requirement Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities under the Energy Policy Act of 1992, and Conforming Other Changes to Form No. FERC-714; Notice of Proposed Rulemaking	)	Docket No. RM 93-10-000

To: The Commission

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL REGARDING FERC'S SECTION 213(b) TRANSMISSION INFORMATION NOPR

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

101 College Road East
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Dated: June 17, 1993

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of:

New Reporting Requirement Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities under the Energy Policy Act of 1992, and Conforming Other Changes to Form No. FERC-714; Notice of Proposed Rulemaking	)	Docket No. RM 93-10-000

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL REGARDING FERC'S SECTION 213(b) TRANSMISSION INFORMATION NOPR

The North American Electric Reliability Council (NERC) is pleased to submit comments on the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on a New Reporting Requirement Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities under the Energy Policy Act of 1992, and Conforming and Other Changes to Form No. FERC-714.

NERC greatly appreciates the thirty-day filing extension the Commission granted to allow additional time to thoroughly investigate possible national security concerns raised near the end of the initial comment period and to put these concerns in their proper perspective.

In brief, NERC's national security concerns can be easily accommodated by changing a word. NERC is supportive of the Commission's reliance on the Regional Councils for information, but not supportive of FERC's new data collection proposals.

Overall Comments

NERC supports the Commission's approach of relying on existing utility information, primarily Regional and subregional power flow data bases that are prepared in the normal course of business. This approach avoids maintaining public files of obsolete data and the inevitable discrepancies between studies. NERC is disappointed, however, that the Commission is also requesting an enormous amount of detailed information from individual utilities on their planning reliability criteria, transmission planning assessment procedures, and an evaluation of future transmission system performance. The Commission's assumption that providing potential transmission users and others with "...the basic planning tools of the existing and planned-for system so they can perform their own studies and reach their own conclusions..." is incorrect. Instead, it will result in an immense amount of data on file with FERC and, in NERC's view, will not meet the objective of the statute. There is no way, not just no simple way, to meet the letter of the law using this approach. The nature of interconnected electric transmission systems, governed by the laws of physics, prevent a simple determination of "...potentially available transmission capacity and known constraints..." The four interconnected electric transmission systems in the United States and Canada are totally unlike the "switched" networks of the telephone, pipeline, and transportation industries that are so often incorrectly used for comparison. The electricity flow patterns are controlled by regulating the generators, not by switching the paths on the network. If potential users want to know if a transmission system can accommodate additional transfers, they will have to ask the owners and operators of that generation and transmission system. Rather than requiring the collection of vast amounts of raw data and information that could ultimately mislead potential users, the Commission should strongly encourage and support direct participation by potential transmission users in the coordinated planning and operations that take place within the framework of the Regional Councils and their various subregional groups.

On the matter of national security, NERC's concerns can be fully addressed with a change in the wording, not the substance. The Commission should change the wording of its request to eliminate the word "critical" from its specific instruction (Form No. 715, Part 5) that

requires transmitting utilities to submit a list of "critical facilities" normally used in performing its contingency analyses. FERC may instead wish to ask for the various contingencies the utility typically tests against in its application of its reliability criteria. This will eliminate any misunderstanding that might arise from the security community's interpretation of "critical facilities." The NERC Board of Trustees has long resisted creating a list of critical facilities that could be turned into a "hit list" for terrorists and saboteurs.

Reliability Criteria — The request for information from individual respondents on reliability criteria, assessment procedures, and results of assessments (FERC Form No. 715, Parts 4, 5, and 6) is open-ended and goes far beyond what is reasonably needed to perform "preliminary" or "pre-request" screening analyses. The Commission should rely as much as possible on information that is already filed by the Regional Councils with the U.S. Department of Energy (DOE) on Form No. OE-411, which should be more than adequate for preliminary and pre-request screening purposes. The Commission could reserve the right to ask for more specific and detailed information for specific cases.

Independent vs Cooperative Studies — Providing data and other information to potential transmission users so they can perform their own independent studies may mislead potential users and ultimately result in more adversarial confrontation and expense. It would be more effective to encourage coordinated and cooperative efforts at all levels of study between the potential transmission users and the affected electric utilities. Such coordination of planning and operation as takes place within the framework of the Regional Councils should be supported and encouraged by the Commission.

Hourly System Lambda — The Commission's stated reason for requesting hourly system lambda data (FERC Form No. 714) as "intended to permit the replication of production cost simulations used in generation and associated transmission planning" is technically incorrect. Lambda is the incremental cost of the next megawatthour of electricity and is used for real-time economic dispatch,

not production cost simulations. In fact, system lambda is often an output of a production cost model, not an input. Reporting of hourly system lambda data also raises some issues of potentially unfair competition. NERC recommends this reporting requirement be eliminated.

Hourly Loads and Forecast Demands — The request for information from individual respondents on hourly load data and actual and forecast demands (FERC No. Form 714, Part III) duplicates much of what is already collected and exists in data bases managed by NERC or the Regional Councils. The Commission should explore the suitability and adaptability of existing sources of data in NERC and the Regional Councils before requesting additional data from individual respondents.

NERC's Unique Mission — Reliability

The members of NERC are the nine Regional Councils and one affiliate. Every utility in the United States, Canada, and a small part of Mexico that generates electricity is a member or is involved in some way with one of these Councils. Regional Council members represent all segments of the electric utility industry — federal, investor-owned, rural electric cooperative, and state/provincial/municipal. The electric utilities formed NERC in 1968 with one objective — to promote reliability of electricity supply. In short, NERC helps electric utilities work together to keep the lights on. It does this by creating and monitoring conformance to criteria, standards, and guides for reliability — the "rules of the road" for operating and planning electric generating and transmission systems. The electric transmission networks in North America are strong, flexible, and economically optimized within the limits of these consistently applied reliability criteria, standards, and guides.

National Security Issues

The Commission can fully address NERC's concerns on national security with a change in the wording, not the substance. The Commission should change the wording of its request to eliminate the word "critical" from its specific instruction (Form No. 715, Part 5) that requires transmitting utilities to submit a list of "critical facilities" normally used in performing its contingency analyses. FERC would get the intended response by asking for the various contingencies the utility typically tests against in its application of its reliability criteria. This will eliminate any misunderstanding that might arise from the security community's interpretation of "critical facilities."

NERC requested and received a thirty-day extension for filing comments on this NOPR because of concerns raised by security experts in both the electric utility industry and the federal government, including the Federal Bureau of Investigation and the Department of Energy, regarding possible national security implications of parts of the proposed reporting requirement. NERC is looked to on these security matters because it is responsible for assuring the reliability of North America's bulk electric systems and is the sponsor of the Electric Utility Threat Assessment Group.

The Group was formed at the request of the U.S. Department of Energy to interface with the federal government on possible terrorist threats against electric power facilities and other national security issues. It is in fulfilling these roles that NERC needed additional time to thoroughly investigate these concerns, put them in their proper perspective, and, if necessary, suggest ways to deal with them.

Our investigation and discussions showed a misconception among security experts regarding how publicly and routinely disclosing transmission line loadings could increase the vulnerability of transmission facilities to sabotage and terrorism. These experts now have a better understanding of how electric transmission systems work, the nature of the data requested, and their concerns have been ameliorated. These agencies have agreed to defer to NERC to speak to the national security issues. NERC only asks that the word "critical" in "critical facilities" be dropped or changed.

Since the mid-1980s, the Department of Energy and NERC have worked closely to reduce the threat of sabotage and terrorism to the bulk electric systems of North America and to address the need for utilities to be prepared to respond to such threats. In 1987, NERC formed a National Electric Security Committee (NESC) to develop a proposed program for (a) reviewing threats to the interconnected electric systems of the United States, (b) an organizational approach to analyze the nature and scope of such threats, (c) suggesting areas of consideration of viable and feasible enhancements to utility emergency preparedness, and (d) indicating strategies to address any appropriate improvements.

One of the specific directions the NERC Board gave to the NESC was to not develop a blueprint, a "hit list," or a critical facilities list for the United States that would be held in a central repository(s) and could fall into the hands of saboteurs or terrorists. It further directed that any identification of "critical facilities" that might be made should be kept internal and confidential by the utility on whose bulk electric system the facilities are located.

A list of key NERC activities relating to national security are:

— NERC Board of Trustees formed the National Electric Security Committee in January 1987 and accepted the Committee's recommendations in October 1988.

- NERC encourages electric utilities to establish and maintain working relationships with local Federal Bureau of Investigation agents and other law enforcement agencies.
- NERC has established a working relationship with the FBI's Counterterrorism Planning Unit, helped create an Electric Utility Facility Proper Names and Contacts Data Base to help detect possible threats against electric power facilities, and participated with the FBI in its Key Assets Protection Program.
- NERC, at the request of the U.S. Department of Energy, sponsored the formation in October 1991 of the Electric Utility Threat Assessment Group to interface with the federal government on possible terrorist threats against electric power facilities and other national security issues.
- NERC entered into a security agreement with the Department of Defense for the protection of classified information contained in its Power Line Carrier Data Base. This Data Base, which is less detailed than what the Commission may be proposing, has been classified by the United States government.
- NERC worked with the Office of Technology Assessment on its study of *Physical Vulnerability of Electric Systems to Natural Disasters and Sabotage*, June 1990.
- NERC President Michehl R. Gent testified in hearings before the Senate Committee on Governmental Affairs on the Vulnerability of Telecommunications and Energy Resources to Terrorism, February 1989.

More recently, NERC has worked with the Federal Bureau of Investigation to assist them in protecting the electric system infrastructure and to assure that their information gathering activities would not result in the compilation of a "hit list" of critical facilities. The Commission's Observer to the NERC Board of Trustees may remember reports on NERC's efforts in this regard during Operation Desert Storm/Desert Shield.

NERC has a long history of guarding against any activity that might result in the creation of a centralized "hit list" of critical bulk electric system facilities, and has cooperated with the

Department of Energy, the Federal Bureau of Investigation, and the Department of Defense in these matters.

Specific Comments on FERC Form No. 715 — Annual Transmission Planning and Evaluation Report

Part 2: Regional or Subregional Power Flow Base Cases

NERC supports the Commission's approach of relying on existing utility information, primarily Regional and subregional power flow data bases that are prepared in the normal course of business. This approach avoids maintaining public files of obsolete data and the inevitable discrepancies between studies.

The Commission has appropriately recognized that assessing transmission capacity and constraints requires a great deal of system-specific experience and engineering judgment, and that the power flow data and other information requested are useful only for rough screening studies that will ultimately require "...more extensive, detailed analysis which would incorporate the most recently available information and specific information about the requested transmission service."

Each Regional Council, and in some cases groups of Regional Councils, prepares a series of base case power flows. The future years and conditions modeled vary from year to year to meet specific study needs. Because these models take a great deal of time and effort to prepare, potential transmission users should use the available models and not expect special studies to be prepared for pre-request screening analyses.

Power flow models of the future system are only best estimates at a particular point in time. As a result, it is not practical to expect that all possible system constraints will be identified and evaluated. Detailed studies are usually done only for those constraints that are expected to affect operations or future additions to the system. New constraints can arise that may not be reflected in the currently available set of models.

The NOPR implies that the NERC Multiregional Modeling Working Group (MMWG) cases are used directly by Regions and subregions. They are used only as a basis for developing more detailed models of the area under study — primarily to assure an adequate and consistent "equivalent" representation of the rest of the interconnected system. The MMWG cases themselves would not be appropriate for use directly by a potential transmission user.

If potential users want to know if a transmission system can accommodate additional transfers, they will have to ask the owners and operators of that generation and transmission system. Rather than requiring the collection of vast amounts of raw data and information that could ultimately mislead potential users, the Commission should strongly encourage and support direct participation by potential transmission users in the coordinated planning and operations that take place within the framework of the Regional Councils and their various subregional groups.

Part 3: Transmitting Utility Maps and Diagrams

NERC suggests that the Commission consider accepting as an adequate response to this item the Regional Council transmission line maps that are already submitted as part of the DOE Form No. OE-411. These maps should be sufficient for screening purposes. The level of detail in the single-line schematic diagrams requested goes well beyond what would be reasonably needed for screening analyses. Also, the expertise required to be able to use this type of information is rarely found outside of the specific utility that prepared these maps and diagrams.

Part 4: Transmission Planning Reliability Criteria

Part 5: Transmission Planning Assessment Practices

Part 6: Evaluation of Transmission System Performance

The request for information from individual respondents on reliability criteria, assessment procedures, and results of assessments (FERC Form No. 715, Parts 4, 5, and 6) is open-ended and goes far beyond what is reasonably needed to perform preliminary and pre-request screening analyses. The Commission should rely as much as possible on information that is already filed by the Regional Councils with the U.S. Department of Energy (DOE) on Form No. OE-411, which should be more than adequate for preliminary and pre-request screening purposes. The

Commission could reserve the right to ask for more specific and detailed information for specific cases.

The Commission's stated basis for requesting the detailed criteria of individual respondents is "... to allow its use by others in planning studies that reasonably replicate those of the respondent." No amount of detailed information on criteria, assessment procedures, and assessment results will enable others to replicate a utility planner's assessment that is based on years of experience, detailed knowledge of the system, and good engineering judgment. There are many assumptions, limitations, accepted practices and procedures, data handling methods and interpretations involved in these studies that have evolved in the overall planning process that are not written. These include particular details such as how generation is shifted to model transfers, determination of transfer points, normal and emergency rating definitions for transmission facilities, and selection of contingencies to be studied. Consideration must be given when using these base models for further studies or extrapolating information, especially the possible effects any proposed system facility addition might have on existing lower voltage facilities in the vicinity of the addition.

Thermal limits on transmission facilities are rarely the only constraint to transmission system use. Dynamic stability limits, voltage limits, and voltage stability limits often dictate how much power can be reliably transferred even when transmission lines are loaded to less than their thermal capability.

Providing data and other information to potential transmission users so they can perform their own independent studies will not be as effective as encouraging more coordinated and cooperative efforts at all levels of study. Such coordination of planning and operation as takes place within the framework of the Regional Councils should be supported and encouraged by the Commission and potential transmission users should be encouraged to participate in these activities. No amount of raw data and information collected by the Commission will be sufficient "... to allow its use by others in planning studies that reasonably replicate those of the respondent."

Detailed evaluation of system performance versus criteria is an open-ended request. This could be interpreted as requiring copies of all study files of every electric utility. Keeping in mind that the information is intended only to allow potential transmission users to perform preliminary and

pre-request screening analyses, the Commission should make every effort to use information that is already available in existing reports such as the Regional OE-411 reports.

It remains to be seen if pre-request information in the form of base case power flows, reliability criteria, etc., will actually reduce the potential for disputes. Ideally, potential transmission users should work closely with transmission owners to jointly evaluate the impacts of the proposed use of the transmission system. Running a few load flows based on the base case information available will provide the potential user with very limited insight at best. It will most likely lead to a debate over how the base case data was used, mislead potential users, and ultimately result in more adversarial confrontation and expense.

Specific Comments on Proposed Changes to FERC Form No. 714

Part II, Schedule 6: Control Area Hourly System Lambda

The Commission's stated reason for requesting hourly system lambda data (FERC Form No. 714) as "intended to permit the replication of production cost simulations used in generation and associated transmission planning" is technically incorrect. Reporting of hourly system lambda data also raises some issues of potentially unfair competition. NERC recommends this reporting requirement be eliminated.

The "replication of production cost simulations" cannot be done with hourly system lambda data. To do this, the Commission would need the input-output curves, proven by actual testing, for each generating unit on each fuel type. The output from these production costing simulations could be the incremental cost, system lambda, for each hour.

These data do not contribute to the Commission's ability to "monitor and understand the performance of the wholesale electric market." It is not clear that this 'monitoring' function is to be limited to the wholesale market. Also, requiring control areas to disclose hourly system lambda data may place electric utilities at a disadvantage when competing for wholesale sales against competitors that are not subject to this requirement.

The timeliness of the data is the key. Having lambdas available to the public in real-time may be anti-competitive. After-the-fact system lambda data do not reveal many important characteristics of system operation: incremental and decremental costs, transmission constraints, must-run generation for area protection and voltage control, contract requirements with electric wholesale generators (must-run), fuel use restrictions, environmental limits, and other system operating constraints. Making year-old hourly system lambda data available suggests, incorrectly, that it has some value in forming judgments about system cost and operation.

Part III, Schedule 2: Planning Area Hourly Demand and Forecast Summer and Winter Peak and Annual Net Energy for Load

The request for information from individual respondents on hourly load data and actual and forecast demands (FERC Form No. 714, Part III) duplicates much of what is already collected and exists in data bases managed by NERC or the Regional Councils. **The Commission should explore the suitability and adaptability of these existing sources of data before requesting additional data from individual respondents.**

Planning area data on annual net energy for load and peak demand are already collected by the Regional Councils in preparing their OE-411 reports. NERC strongly supports the option of having respondents authorize their Regions to release these data rather than submit it individually. NERC would be pleased to consider making these data available electronically if the Regions and the Commission concur.

NERC already maintains an Hourly Load Data System. Rather than duplicate this, NERC suggests the Commission review these data and identify how they would have to be modified to satisfy its needs.

Respectfully submitted,

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

By: _____ and _____

Michehl R. Gent
President

David R. Nevius
Vice President

Dated: June 17, 1993

DRAFT

ESTABLISHING FIRM TRANSMISSION RIGHTS USING A "RATED SYSTEM PATH" MODEL

Steven L. Walton

The transmission access debate, which has been underway in the United States for over 60 years[1], entered a new phase with the passage of the Energy Policy Act of 1992 (EPACT'92). Under EPACT'92 Congress granted FERC the authority to order all transmission owners to provide transmission services, thereby deciding the policy question in favor of mandated access over purely voluntary access. Given the potential for much broader use of the transmission system by third parties, the nature of the service provided must be better defined than it has been in the past. Such an improvement in definition is a prerequisite to any discussion of price, terms and conditions of service. This paper proposes the use of a "rated system path" model[2] as an approach to defining firm transmission rights. The rated system path model is an extension of the transmission rating practice developed in the Western System[3]. This paper also discusses the use of various kinds of models for system analysis and their relationship to a commercial model on which transmission transactions can be based.

Transmission service, commonly called "wheeling" is not new to the industry, but because its scope has been somewhat limited, the art and practice of transmission service and pricing are still in a relatively infant state. To a large extent, wheeling has been treated as a system surplus made available using existing transmission. FERC has historically used an embedded cost, postage stamp pricing model. The postage stamp model reduces an entire transmission system to a single bus[4] and ignores the spatial geometry of the network upon which engineering design is necessarily based.

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The service obligation of the transmitting utility is often defined using a "contract path" described in terms of specific transmission system facilities between a point of receipt and a point of delivery without regard for any effect upon the overall transmission system. Both the postage stamp price and the traditional contract path obligation definition have little to do with system operations or planning nor are they consistent with one another. Better models of obligation and pricing will be needed in the future.

The foundation of a practical system for providing wheeling services has to be a definition of tradeable, firm transmission rights. The largest cost a transmission provider faces is capital related, i.e., a return on and recovery of the investment made in plant and equipment. By comparison with these fixed costs, the variable costs, operation, maintenance, and losses, are small. Without a reasonable expectation of capital cost recovery, based on firm commitments by customers, investors will be reluctant to build new transmission facilities. As a result, the definition of firm transmission service and its associated pricing must address the process of capital investment and fixed cost recovery.

Capital investment decisions are made with an expectation of increased system capacity by the constructing utility. Therefore, a good model of transmission service obligations should recognize the process by which system capability is created through the design process. Once a system for defining tradeable firm rights is in place, a market can exist where firm rights are traded for either long or short term use.

In an effort to address the traditional contract path model's weak linkage to the transmission system, alternatives have been proposed based on power flow studies, i.e., "actual" flow methods.[5] An actual flow model defines transmission service as a

product indivisibly provided by the grid, hence transmission owners are compensated based on the fraction of the flow which a given transaction imposes on each of their lines. While having intrinsic technical appeal because of its reliance on power flow calculations, an actual flow approach does not directly address the process by which capacity is created. The firm transfer capability of a transmission network is defined not by the flow of power with all lines in service, but by the system's ability to continue to operate when equipment failures occur. Compensation based on actual flows will not necessarily reward the parties who have created the "strength" of the network to operate under such adverse conditions.

Hogan proposes the use of a "contract network" model for transmission pricing and for defining network contract rights in an open access environment.[6,7] The contract network model is derived from an evaluation of efficient system operation in the short term using the difference in spot market bus prices as the marginal cost to move power from one bus to another. Hogan's model merges both short term pricing and implicit capacity trades into a single transaction. Contract network prices for moving energy from one bus to another cover variable costs including both losses and congestion costs. Either a centrally dispatched power pool or a grid operator is assumed, as an integral part of the contract network model. The grid operator has the ability in this model to redispatch all resources, collect charges from users and re-distribute revenues to holders of firm rights.

The contract network model, however, does not, address long term firm rights directly. It assumes that some mechanism exists for deciding on system design and for covering the capital costs incurred. These two assumptions, however, are non-trivial

and must be addressed at the outset before a short term operational proposal can function.

In the development of the contract network model, it is assumed that system capacity varies from hour to hour and cannot be defined in such a way as to make it divisible between different contracting parties. This interpretation seems to be a result of examining the system from only the operational optimization viewpoint as opposed to the planning viewpoint. By examining transmission design and rating practices, it is possible to devise a system of firm transmission rights which are tradeable as envisioned by the provisions of EPACT'92.

In the Western System, a practice of system ratings has evolved which establishes the simultaneous capacity of sets of parallel transmission facilities. The division of these simultaneous ratings, between the owners of the parallel facilities, is based on the contribution each facility makes to a simultaneous system rating. A "rated system path"[8] may be defined, based upon these simultaneous ratings, which defines the portion of the simultaneous system capacity to which the contracting party has an established right or entitlement. The rated system path model, proposed here, provides a practical basis for defining firm transmission rights without introducing the complexities of the contract network model.

Because of the way in which they are defined, the rated system path transmission rights are tradeable and could be used to establish a secondary market. Hunt and Shuttleworth propose such a "hub and spoke" model in which such transmision rights can be traded between system users[9]. "Hubs" are regional trading points to which resources and loads are connected by "connection spokes". Major

transmission routes between hubs are called "transit spokes" where transmission capacity may be constrained. The rated system paths described in this paper could serve as the transit spokes of a "hub and spoke" spot market.

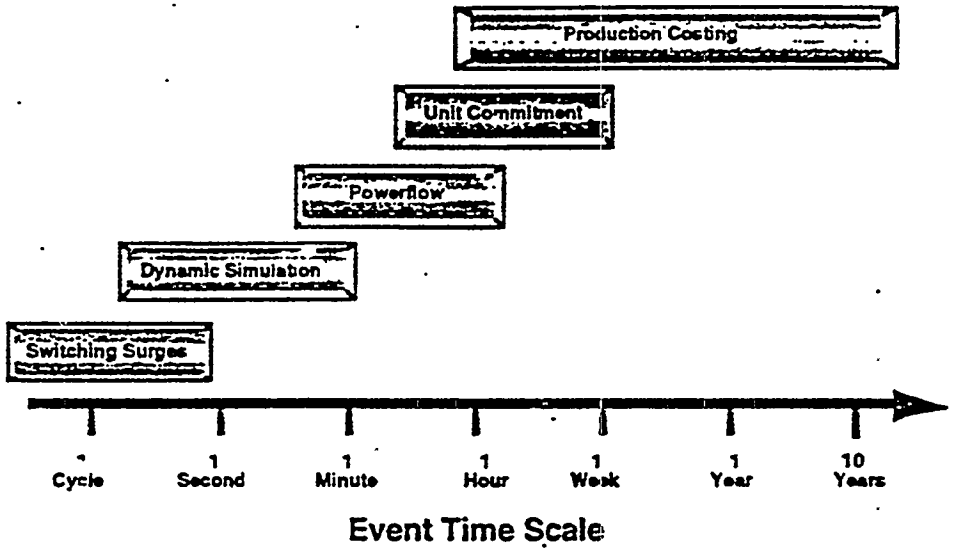
It is unlikely that any one model can be applied uniformly to all systems without having a poor result for some of the systems. Any model has limits to its applicability, so selection of a preferred model will depend upon how well it fits the physical characteristics and existing contract structure of a given system. The system rating practice described here has evolved from experience in planning and operating in the Western System. There are substantial physical differences between the Western System and Texas system or the Eastern interconnection and its subsystems. As a result, the rated system path model's applicability outside the West would have to be weighed in terms of the characteristics and practices of other systems.

A WORD ON MODELING

When devising any model, whether for physical systems, economic operations or human behavior, it is well to remember that any model is only an approximation of previous observations. Although an approximation, a model can be useful in problem solving as long as its limitations are recognized. While the dangers of over simplifying are easily recognized, the temptation to build unecessarily intricate model should also be avoided. The goal is to produce a model which describes the salient phenomena with the least complication. A model of transmission service obligations tied to actual power flows will introduce a high level of complexity which may not be necessary and could in fact make the definition of tradeable long term system rights problematic.

Multiple engineering tools are used for analysis and design of the transmission system. This is portrayed in Figure 1, where the applicability of various models is shown relative to the time scale of system events for which the designer must plan. A power flow study uses simple electrical models which describe the electrical characteristics of components of the transmission network and the location load and

Figure 1
Transmission System
Simulation Models



generation within that network. The power flow model can be used to study steady state conditions in the network, i.e., conditions which do not change much over a period of a few minutes or more. The power flow model cannot, however, be used to investigate events which can occur in a time interval of a few seconds or less. For

such studies the dynamic behavior of the system must be modeled using electro-mechanical equations for rotor motion as a function of time. This enhanced model can be used for stability studies where events like line faults can lead to a loss of synchronism between the generators in the system. A third model is necessary to study even faster events such as voltage surges which can occur in milliseconds or less. All the models, as well as a number of others, are used at different stages of the design process depending upon matching the accuracy of a given model to the question to be investigated.

In order to write a contract for transmission service, the contract analyst needs a "commercial" model, i.e., one suitable for conducting commercial operations. The commercial model characteristics will of necessity differ from engineering models because its purpose is different. A commercial model must be understandable to all the professional communities involved in contract execution, contract approval and delivery of services to customers -- accountants, attorneys, economists, engineers, dispatchers, and financial analysts. The commercial model of wheeling must describe a tradeable product and incorporate the cost impact of the customer usage on the decision making of the designer. It does not necessarily have to be directly tied to any of the engineering tools used for system analysis and design which often ignore financial and ownership considerations.

Just as engineering tools focus on various aspects of the physical system, the commercial model should focus on the chief effects influencing system design decisions. Since system planners use failure modes as the defining measure of system adequacy, actual power flow during operations may not be particularly

significant in determining the capacity rights which a utility has in an interconnected system. What is significant for determining transmission capacity rights is the net change in system capability that a given project adds to the total system. An increase in system transmission capacity depends upon the network already in place when an addition is made.

THE RATED SYSTEM PATH MODEL

The geography of Western North America has a dramatic impact on the nature of the Western System. Its topology is dictated by the physical barriers and assets of the West. Massive mountain ranges -- the Cascades, the Sierra Nevada, and the Rockies are substantial barriers to the building of transmission lines. Large arid or semi-arid plains and basins lie between these mountain systems which concentrates population in widely separate locations where water resources are available. Extensive resource diversity exists between hydro-electric and thermal generation, and climatic variation from North to South provides substantial load diversity[10]. The result is a system marked by long, high voltage transmission lines connecting widely separated concentrations of load and generation.

Energy transfers from one end of the system to the other have been common for some 20 years. For instance as snow melts during the Spring, surplus Pacific Northwest energy is sold throughout Southern California and the Desert Southwest. Conversely Northwest utilities make winter peak purchases from summer peaking utilities in the Southwest. A single reliability council, the Western Systems Coordinating Council (WSCC) covers the entire Western System.

Because the Western System is largely composed of long lines, crossing large areas of low load density, the transfer capability of major transmission lines are largely dictated by system dynamic considerations. Some contingencies can have immediate, system wide impacts. Control action response must often occur within seconds to prevent a loss of synchronism between groups of generators.

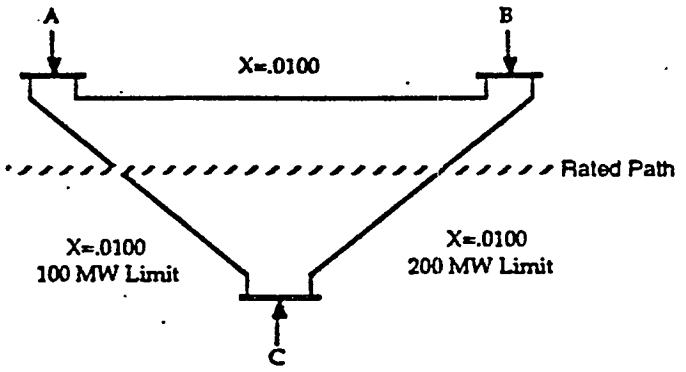
The nature of the Western System requires that transfer capability of major facilities be defined as a part of a network or system path rating, rather that as the rating of any one component of the system. System path ratings are seldom based on the thermal rating of a line[11], instead system ratings are generally based on the level of pre-disturbance loadings permissible for a set of parallel lines. Anything above this permissible loading level can result in a loss of load and a system break-up when an equipment failure occurs. Studies of system electro-mechanical dynamics, often called stabiltiy studies, are performed to evaluate the ability of the system to withstand the loss of network elements. A minimum transient voltage criteria is used as the threshold at which loss of load occurs[12]. By adhering to pre-disturbance loading limits established by such studies, the system is able to operate reliably.

APPLICATION TO AN EXAMPLE SYSTEM

To better understand the concept of a system rating, consider the simple three bus example shown in Figure 2 which connects three utilities, A, B, and C. In this example A and B are exporting energy to C. For simplicity, the impedances[13]

between the three buses are equal and rating on line A-B will be ignored for simplicity[14].

Figure 2
Three Bus System



Each of the lines in the system is subject to failure at any time. For instances, if lightning strikes line A-C, the electrical insulation will temporarily fail and a current path to ground will be established. Control devices called relays will detect this short circuit or fault and operate circuit breakers to disconnect line A-C from the system. This prevents damage to line A-C and allows the remaining parts of the system to continue to operate. The capability of the system must, therefore, be based on its ability to operate successfully when such an outage event occurs. Reliability criteria are established between interconnected utilities to set the standards for the kind of response acceptable for a given class of events.

To establish the "North to South" rating of this example system, we begin by drawing a line across the system which intersects the parallel facilities which are to be

rated. This line is represented in Figure 2 by a horizontal dashed line. Such a set of parallel facilities, intersected by this line, is referred to as a "path" for which a transfer capability can be established. The reliability criteria for this sample system requires that a single contingency line outage must be survivable. For the purpose of this example, we assume that stability studies show that if the flow across the path is 200 MW or less when line A-C is lost, the system will be stable. However, if system loading is in excess of 100 MW when line B-C is lost, utility C's voltage will drop low enough in the initial seconds of the disturbance, that load will be lost in C's system. The loss of line B-C, is therefore the worst case contingency in this system. As a result 100 MW is the upper rating of this path. The fact that line B-C can transfer 200 MW for the loss of A-C has no bearing on the rating, because the system cannot survive the loss of B-C if the system is loaded to that higher level.

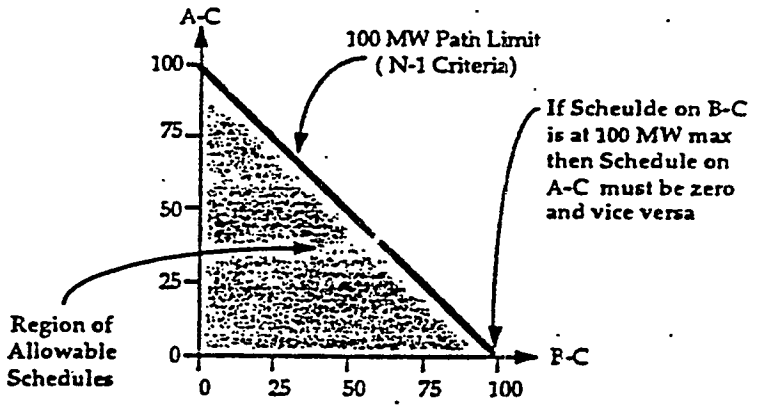
Table 1
Transfer Capability Rating Studies of Three Bus System

Case No.	Power Schedules		Base Case Power Flows		Outage Case Power Flows	
	Bus A	Bus B	Line A-C	Line B-C	Line A-C	Line B-C
1	0	100	33	67	100	0
2	25	75	42	58	100	0
3	50	50	50	50	100	0
4	75	25	58	42	100	0
5	100	0	67	33	100	0

Table 1 shows a set of power flow results used to establish the limits on power scheduling which A and B must observe to keep path loading at or below 100 MW.

The schedules from both A and B to C varied between 0 to 100 MW for each utility. For instance in Case No. 1, B schedules an export of 100 MW and A schedules zero. The second set of columns, represent the system power flows with all lines in service for this combination of schedules. The net schedule from the two buses has been limited so that when the limiting outage case is checked, as shown in the third set of columns, the resulting flow on A-C is below the 100 MW limit. Note that while each power flow base case has a different set of line flows, the result is the same when an outage occurs. The outage of line A-C is not shown, because the result will be well below limits and of little interest in establishing a system rating.

Figure 3
Three Bus System - Capacity Diagram

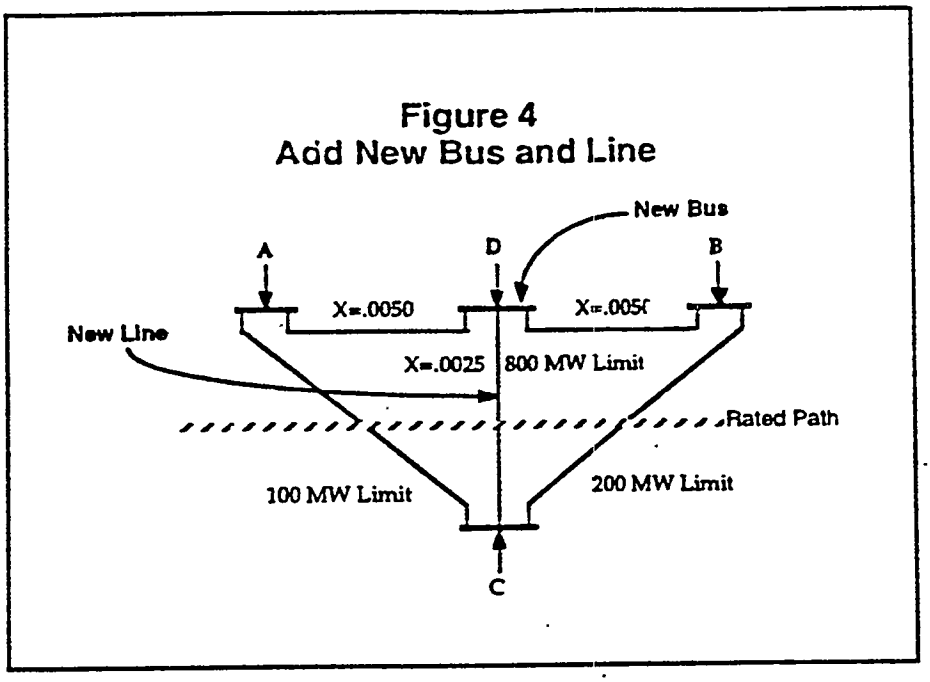


In order to make a series of power flow cases easily understood, a graphical representation like Figure 3 can be drawn. The line representing the system limit is drawn by plotting the flows from the base cases. The area under the 100 MW limit line defines the capability of the system. This graph, commonly refered to as a nomagram

in the Western System, portrays the permissible coordinated schedules of power which A and B can make to C.

The system rating depends upon both lines since neither utility can maintain a firm transfer to C without the other's line in place. The firm system transfer capability is therefore an asset created jointly by the investment of the two parties even though the investments may have been made independently. Each line in the network acts as a part of the whole, that is, as part of a single system. The value of any given project is intrinsically tied to the existing system to which it is added. To establish a firm right for both utilities A and B, the 100 MW capability must be allocated between them. For the purpose of this example, it assumed that A and B split the capacity with 50 MW of rights to each.

Suppose that A is scheduling 50 MW and B has a schedule of zero. One-third of the schedule will flow on line B-C, about 17 MW. Should B be compensated for this flow when it is using only its own share of this rated system path? Those favoring loop flow compensation or other forms of actual flow compensation, would likely argue in the affirmative. However this looks past the fact that because the system has been pre-rated and a capacity entitlement established, B's capacity rights have not been affected by A's 50 MW transfer. B can still use its 50 MW right without overloading the system or other options are available to fully utilize the system. A and B could work out an arrangement to use each other's rights on a non-firm basis. B could sell the capacity to an upstream utility to make a transfer. Utility A could purchase the capacity to make a larger firm sale. In any of these cases, the full, reliable capability of the system can be utilized.



To reinforce these concepts consider an extension of the example system, shown in Figure 4, when a new resource is added at D, between buses A and B, with a new line from D to C. Again Utility C is importing energy from the sources to its North. The new line is assumed to operate at the next higher voltage level (for instance adding a 345 kV line to a 230 kv network) which accounts for its much lower impedance compared to the other lines. The project sponsor estimates that line D-C has a non-simultaneous rating of 800 MW. With all lines in service, line D-C will have the heaviest loading as shown in the base case flows in Table 2. D-C's loss will, therefore, be the limiting outage for this system.

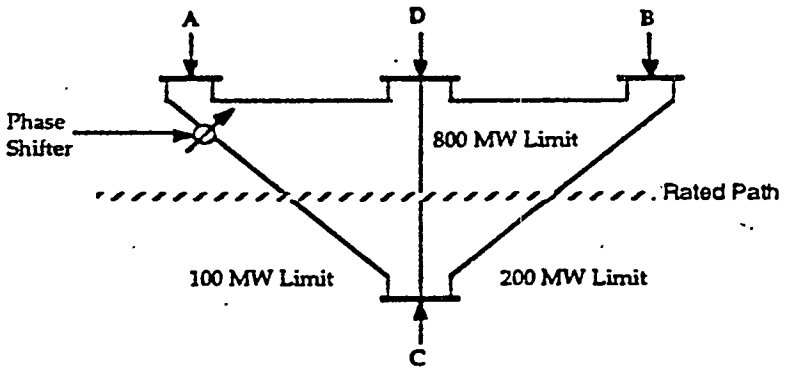
Table 2
Transfer Capability Rating Studies With
New Line and Bus Added
to Three Bus System

	Power Schedules			Base Case Power Flows			Outage Case Power Flows			
Case No.	Bus A	Bus D	Bus B	Line A-C	Line D-C	Line B-C	Line A-C	Line D-C	Line B-C	Path Sum
1	100	67	0	50	100	17	100	0	67	**167**
2	75	83	25	44	112	27	100	0	83	**183**
3	50	100	50	38	125	38	100	0	100	**200**
4	25	117	75	31	138	48	100	0	117	**217**
5	0	134	100	25	151	58	100	0	134	**234**

When stability studies are run, it is discovered that once again, the capability of line A-C limits the path's transfer capability. If more that 100 MW is flowing on line A-C after the failure of line D-C, load loss occurs in C's system. In Table 2, the power scheduled from A and B has been limited to 100 MW as before and the schedule from D has been adjusted to give a post-disturbance loading on A-C of 100 MW. The post-disturbance loadings are shown in the outage case power flow columns. These studies show the new path rating varies between 167 and 234 MW so the capacity added by the new project is between 67 and 134 MW depending upon schedules. The small increase in simultaneous capacity indicates that project D is poorly matched to the existing system. The fact that the new line D-C carries the bulk of the flow when all lines are in service, does not mean that A and B are doing anything improper or that they should compensate the owners of line D-C for "loop flow". Unless line D-C is the first stage of a much larger project to upgrade transfer capability, the design proposed

is indicative of poor engineering. The small gain in transfer capability could probably have been obtained by a much lower investment.

Figure 5
Add New Bus, Line & Phase Shifter



Since line A-C's loading is the limiting factor in the path rating, project D could get more transfer capability by entering into an agreement with Utility A to install a phase shifting transformer (also called a phase shifter or phase angle regulator)[15] in line A-C as shown in Figure 5, to control flows so that post-disturbance flows will be acceptable. In Table 3, the base case power flows are shown with all lines in service and the phase shifter operating at zero degrees, i.e., not regulating. The outage case power flow columns shows the line flows with the phase shifter regulating and with the loss of line D-C for the same resource schedules.

Table 3
Transfer Capability Rating Studies With
New Line, Bus and Phase Shifter Added
to Three Bus System

	Schedule			Base Case (1)			Outage Case (2)			
Case No.	Bus A	Bus D	Bus B	Line A-C	Line D-C	Line B-C	Line A-C	Line D-C	Line B-C	Path Sum
1	100	200	0	67	200	33	100	0	200	300
2	75	200	25	58	200	42	100	0	200	300
3	50	200	50	50	200	50	100	0	200	300
4	25	200	75	42	200	58	100	0	200	300
5	0	200	100	33	200	67	100	0	200	300

Notes: 1. Phase shifter at zero degrees
2. Phase shifter regulating to 100 MW

With the phase shifter in place, the system can be operated with a total path flow of 300 MW. Project D can now claim 200 MW as its transfer capability since that is the capacity added to the total system path. To achieve this level, however, it would need to have reached an agreement with the other parties on installation and operation of the phase shifter. The phase shifter would not have to be operated all the time, only when it was necessary to hold post-disturbance flows on A-C to under 100 MW.

As in this case, phase shifting transformers can permit more efficient use of the capital resources invested in transmission although they may raise system losses. It is true that a system without phase shifting transformers will have lower overall losses, but that implies that additional transmission can be built to achieve the same overall transfer. The objective function to be optimized for design is not short run transmission

system operation, but lowest cost delivery of energy to ultimate customers. Given the cost of new transmission construction, the most efficient thing to do may be to let transmission losses rise and maximize transfer capability by using a phase shifter or other power control devices which may become available in the future. Environmental issues associated with obtaining right-of-way add additional non-monetary reasons for maximizing the use of existing lines. This is particularly true in the West where virtually any major new transmission line requires at least an environmental assessment and more likely a full environmental impact study since it will cross land administered by the Federal and State land agencies on at least some portion of the right-of-way.

WSCC POLICY AND PROCEDURE FOR RATING TRANSMISSION FACILITIES

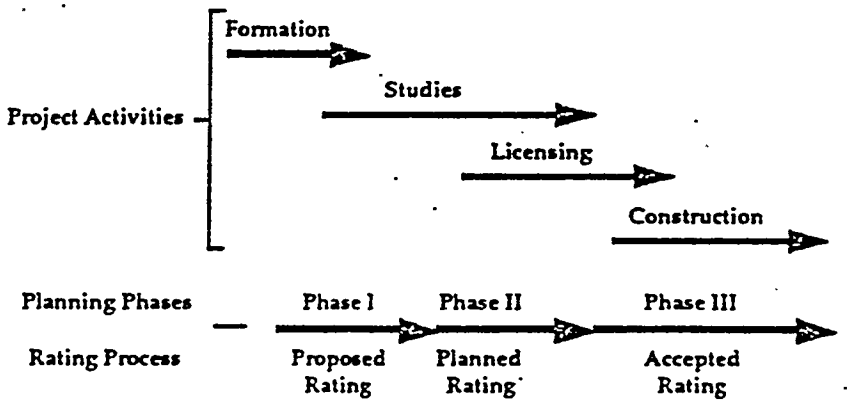
In 1992, the WSCC formally adopted a set of policies and procedures for the rating of new transmission facilities as part of the planning process. This standard has evolved over the past ten years or so as a means of determining the simultaneous capacity of various constrained portions of the Western System. The WSCC reliability criteria, as updated in 1993, provides the basis for evaluating the results of studies conducted as part of any system rating process. The objectives of the WSCC planning process can be summarized as follows:

- Integrate new projects into the system while preserving reliability and efficiency,
- Communicate plans, performance and limitations to all affected parties from project inception to operation,

- Discover simultaneous limitations and resolve curtailment agreements prior to operation, and
- Provide an opportunity for owners of affected facilities to participate in new project study reviews.[16]

The project planning process has three planning phases followed by commercial operation. The relationship between project activities and these planning phases is shown in Figure 6. Phase I commences when a WSCC member makes a submission of data for the "WSCC Significant Additions and Changes to System Facilities Report". This report is a public document which goes to all members and to many other parties, such as State regulators. The submission by the project sponsor includes a "Proposed Rating". During Phase I, the sponsor conducts independent studies to determine a non-simultaneous rating. These studies should take into account any known simultaneous system effects.

Figure 6
WSCC Transmission Rating Process



Phase II begins when the project sponsor submits a Comprehensive Rating Report to WSCC which includes a preliminary plan of service, a project schedule, a "Planned Rating" and studies supporting that rating. During Phase II, studies are conducted to determine both the simultaneous and non-simultaneous ratings with the involvement of an Ad Hoc Review Group. The Ad Hoc Review Group is formed when Phase II begins; it should include all potentially affected parties but is open to voluntary participation from all WSCC members.

Phase III begins when a rating report is submitted with the concurrence of the Ad Hoc Review Group. In Phase III, the project has an "Accepted Rating" which has the same standing as the rating of existing systems for the purposes of other studies. The Accepted Rating is protected as long as the project meets its milestones. If the project is interrupted or delayed, it may be required to repeat Phase II. Phase III ends when the project goes into commercial operation. The facilities rated will include both interconnections to other utilities and lines inside of a utility's territory whenever they are part of an identified system limitation.

Concern has been expressed by a number of observers that utilities could frustrate the opening of the transmission system, provided for by EPACT'92, by manipulating system ratings. The WSCC rating procedure contains inherent self regulating features; understated ratings are naturally penalized. If in an attempt to restrict access a utility underrates its system, it will lose the extra capacity it could have claimed. When a new project demonstrates a later, higher simultaneous rating it will include any capacity which previous projects failed to make public. The new project would claim the full increase demonstrated. Projects sponsors have every incentive,

therefore, to claim as high a transfer capability as they can support. On the other hand, the project sponsor must demonstrate to the Ad Hoc Review Group either that no party is harmed by the established rating or that the harm to any party has been mitigated to the satisfaction of those affected. There is tension in both directions which forces the process toward the "best" answer. Since, WSCC has opened its membership to independent producers, all participants in the wholesale market can be participants in the system planning and rating process.

CONTRACTING OVER RATED SYSTEM PATHS

The Western rating practice described above results in the identification of various sets of facilities, which when considered together, constitute a rated system path where a constraint on transfer capability exists. The allocation of capacity to each project occurs naturally. As the capacity from each successive project is evaluated, the increase in the simultaneous path rating is allocated to the project which created it. When a party wishes to arrange for the wheeling of energy, it may contract with any of the utilities which have a portion of the capacity in the rated system path over which the transmitted energy must pass. The total capacity existing at any given system constraint is not the sole creation of any one of the owners, but has been jointly created by all the facilities involved. These parallel facilities depend on each other to hold the system together when outages occur. Using power flows, at any given point in time to define the transmission right, does not recognize this interdependence.

In the example system of Figure 5, a party could contract with A, B, or D to move energy to C. As long as none of the transmission owners sell or schedule above

transmission capacity "property right", no party is injured. With all lines in service, much of the actual flow will travel over D's system because of its low impedance. This does not mean that D is entitled to compensation. Line D-C was built knowing full well what capacity could be obtained from the design. D should not be rewarded through actual flow compensation for having added a project which is poorly matched to the existing system. This demonstrates the lack of linkage that exists between a given set of power flows and the strength of the system. By using the rated system path model, the facilities which create the strength of the system receive compensation for their capital investments.

When more than one rated system path must be crossed, the party seeking wheeling can purchase capacity at each constraint. The series of rated system paths in which capacity is available becomes the "scheduling path" for the delivery of the wheeled energy. Applied to the Hunt and Shutteworth's "hub and spoke" model, each rated system path would be an identified constraint or "spoke" and the portions of the systems between constraints would be the "hubs"[17]. The capacity which a party purchases across a given rated system path can be resold to other parties in later transactions. This allows non-firm transactions to move over paths committed to various parties for firm wheeling when firm use is below the contract right held by each party.

Because the firm rights are identified in terms of a specific path, they can be transferred to other parties. This facilitates capacity trading, unlike the actual flow commercial models where capacity is defined only between two specific buses in the system which would be difficult to transfer. Bilateral trades can occur with the rated

system path model, whereas an actual flow commercial model requires a party seeking wheeling to contract with more than one party. Such multi-party contracting poses a substantial difficulty unless a pool or grid operator mechanism is in place to cover all the lines of significance to the transfer in question. Even where centrally dispatched pools currently exist, they are not of sufficient size to deal with all the effects on interconnected systems of long distance power transfers.

Can such a system work? Yes. When PacifiCorp filed notice of its Remaining Existing Capacity (REC) in 1989 in compliance with FERC's merger order (Opinion No. 318), the committed capacity was deducted from the total "path" capacity to give the REC. The paths reported were the equivalent of rated system paths, and the filing was accompanied by study results which showed the conditions under which the PacifiCorp capacity rights were determined. While some similarity exists with the traditional contract path model, the rated system path model differs substantially because it is based upon simultaneous ratings of system paths. The physical effects of one party's schedules on another party are not ignored, instead they are built into the path ratings of the system.

LOOP FLOW

What of loop flow? Much has been written and said lately about the need for "loop flow pricing". It is supposedly the great obstacle to open access operations. Unfortunately during the debate over open access to transmission, loop flow was raised by opponents as an obstacle which made open access impossible. Congress apparently decided that even in the face of this argument and many others, that

access to the transmission system was in the public interest, hence the ordering provisions of EPACT'92. The unfortunate side effect of the rhetoric from the open access debate is that it has pre-biased many to believe compensation for wheeling should follow actual flow, i.e., parties should be compensated for carrying loop flow.

As shown above, if system constraints are properly identified, rated and capacity allocated between transmission owners, the presence of loop flow is in itself no demonstration of harm. The only harm which occurs due to loop flow, beyond small differences in system losses, is when a transmission owner is prevented from utilizing the transmission capacity to which it has a right. This, however, is not the thermal rating of its conductor or the non-simultaneous maximum it can obtain ignoring the rest of the system, but its share of the simultaneous transfer capability of the system. As a first measure to avoid restricting use of other transmission owners' capacity, each transmission owner should limit scheduling to its established share of the rated system paths, as is the currently done in the Western System.

Because the location of generation in the areas which fall between the system constraints may vary and because energy may be purchased and resold by third parties, scheduling practice alone will not produce complete control. Other measures need to be put in place to deal with variances from the ideal. In the past a tolerance level or margin was applied to established ratings. In the Western System, it has generally been accepted that loop flow accommodation of 5-10% is more than offset by the benefits of interconnection. In the future, under generalized open access, other measures may be required to permit full utilization of the transmission system during limiting hours. A spot market, based on trading firm transmission rights previously

established, could provide an additional measure for pushing the system toward its physical limits.

Another measure which can be taken to manage loop flow is the use of phase shifting transformers. The development of the "FACTS" technology (Flexible AC Transmission Systems) may provide additional devices in the near future to augment existing control strategies by using devices which employ solid state switching of series capacitors, shunt capacitors, etc[18]. The Western System is particularly well suited to flow control by its topology. A relatively few phase shifters can be strategically placed to control loop flow in a major portion of the system. Such devices are already in place on the East Side of the WSCC "loop"[19]. The phase shifters need not operate continuously, with an associated increase in system losses and wear and tear on the tap changing mechanisms, rather they should be operated to correct conditions where the use of a capacity owner's rights is being restricted by loop flow. In the future, coordinate control action could become part of the economics of the spot market or of central dispatch optimization.

CONCLUSION

Congress has determined that access will be provided in today's network and under today's business conditions; services will be provided by a network with pluralistic ownership and multiple control areas for the foreseeable future. The definition of firm transmission rights in such a system is a necessary pre-requisite to the provision of service. With tradeable firm rights established and a rational method

for pricing these firm rights which assures recovery of fixed costs, a non-firm market can be developed to facilitate operational optimization. The rated system path model described here is an adaptation of system planning and design procedures in the Western System which can be used to define tradeable firm transmission rights. The rated system path model is based on the Western practice of establishing system ratings, and it is the underpinning for many existing business transactions within the WSCC area.

Proposals for actual flow compensation assume that power flow results are the proper basis for scheduling rights. However, this view ignores the contribution that all system facilities make to the ability of the system to handle operating emergencies such as line outages. By examining the contribution each facility makes to the simultaneous transfer capability of the system, a more appropriate division of firm rights can be made. Transmission rights are then based upon the same decision making used in designing system additions which expand transfer capability. The rated system path model recognizes system limitations, yet results in tradeable firm rights, without the need for a grid operator. This is an advantage for the Western System and perhaps other areas where no centrally dispatched "tight" power pool exists.

ENDNOTES

1. Thomas P. Hughes, Networks of Power: Electrification in Western Society, 1880-1930, The Johns Hopkins University Press, Baltimore, MD, 1983, pp. 296-313, 324-326, 331-334, which discusses the Giant Power proposal made during the 1920's and its influence on the formation of the Pennsylvania-New

Jersey Interconnection power pool in 1927 which became the PJM with the addition of Maryland in 1956.

2. As used in this paper the term model is used in the general sense of a formalization of a systems problems ranging from a simple qualitatively description to a mathmatical description used to create computer software for simulating system behavior.

3. The Western System is made up of the synchronously operating electric utility systems in the western United States. It covers geographic area roughly 1000 miles from East to West and 2000 miles from North to South including the eleven western states (Washington, Oregon, California, Idaho, Utah, Arizona, Montana, Wyoming, Colorado, New Mexico and part of Texas), two western Canadian provinces (British Columbia and Alberta) and some facilities in Mexico.

4. A "bus" is a node in the network at which two or more lines or transformers are connected, usually in a switching station or a substation.

5. As used in this paper, actual flow refers to the movement of electrical power over the transmission system, whether historically metered or predicted by power flow studies. In Texas an actual flow method, called "MW-Mile", has been in use for several years. Another method, which has been put forward recently, is the GAPP (General Agreement on Parallel Paths) procedure of the InterConnected Transmission Forum.

   Sometimes actual flows have been referred to as "electron flow". This however is a misnomer based on a misunderstanding of the physics of power movement in an alternating current (AC) system. Power is transmitted by electro-magnetic field effects concentrated in the conductors. The charge carriers are not in fact transported anywhere in an AC system.

6. Hogan, William W. , "Electric Transmission: A New Model for Old Principles", The Electricity Journal, Vol. 6, No. 2, March 1993, pp. 18-29.

7. Hogan, William E., "Contract Networks for Electric Power Transmission", Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-42.

8. The term "rated system path" has been coined here to clarify the difference between a path rating based on simultaneous flows on parallel lines and a simple "contract path" which is based on a single line or a series of single lines. In common reference, the term contract path has been used to refer to both methods which leads to confusion about the difference in Western practice and other approaches.

9. Sally Hunt and Graham Shuttleworth, "Operating a Transmission Company under Open Access: The Basic Requirements", The Electricity Journal, Vol. 6, No. 2, March 1993, pp 40-50.

10. Load diversity refers to the difference in peaking behavior between different types of loads or between load locations which results in a peak system load which is less than the sum of the non-simultaneous peaks of its subparts. For example the Pacific Northwest tends to experience peak loads during the winter heating season while the Desert Southwest tends to peak during the summer air conditioning season. Such seasonal diversity permits the total system to meet its needs with less installed capacity than would be required by the sum of the peaks of each region. Load diversity also occurs due to differences in time zones, time of day variations in industrial operations or residential living patterns and the random nature of individual consumption decisions.

11. For the 230 kV, 345 kV, and 500 kV lines used in the West, the conductor size is often selected to minimize corona and radiated interference rather than for its thermal rating. Except in urban areas, actual loading of these long, high voltage lines seldom approaches the conductor's thermal rating.

12. The voltage at various buses in the system will drop and recover while the system is adjusting to the loss of some network element. The process takes place within a couple of seconds of fault clearing. Such a drop in system voltage can cause motor contactors to open and drop load from the system. Triggering of this self protecting action is a function of both the magnitude and the duration of the voltage drop.

13. The impedance of a network element in an AC system is the generalized term which includes both resistance and electro-magnetic field effects. The lower the impedance of a line, the more power will flow over it for the same set of conditions at its terminals.

14. The impedances used in this example would in all likelihood not produce the stability results assumed in this example. The example, does however, allow explanation of Western System rating practices with a minimum of complexity. To make the example fully realistic, would require much more difficult calculations, but would not add any better understanding of the principles involved.

15. When placed in series with a transmission line, a phase shifting transformer increases or decreases the difference in line voltage angle between the two ends of a line thereby decreasing or increasing the flow over the line. It can

only control the flow in the line in which it is installed. Flows in the rest of the system will continue to follow the path of least impedance.

16. "Policies and Procedures for Rating Transmission Facilities", Western Systems Coordinating Council, July 1992, p. 7-12.

17. Hunt and Shuttleworth, pp. 42-43.

18. Narain G. Hingorani, "Flexible ac transmission", IEEE Spectrum, Vol 30, No 4, April 1993, Institute of Electrical and Electronics Engineers, Inc., New York, NY, pp 40-45.

19. As a part of settlements associated with the merger of Utah Power & Light Co and PacifiCorp, phase shifters were installed in series with its ties to Arizona and New-Mexico (the Sigurd 230 kV and Pinto 345 kV phase shifters respectively). The costs of these phase shifting transformers in Southern Utah are partially paid by Southern California Edison and Pacific Gas and Electric. Western Area Power has installed phase shifting transformers in its ties between Colorado and New Mexico (the Shiprock 230 kV and Waterflow 345 kV phase shifters). Nevada Power and PacifiCorp installed a fifth phase shifter in the Utah-Nevada tie (the Harry Allen 345 kV phase shifter).

DOE/ER/10084-1
Western Interstate Energy Board

SIDE BY SIDE COMPARISON OF THE WATSCO, SWRTA AND WRTA BYLAWS

Part 3 of 3 Parts

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FILING BYLAWS WITH FERC

WATSCO

11. **FILING BYLAWS WITH FERC; APPROVAL OF BYLAWS; TERM OF BYLAWS; AMENDING OR TERMINATING BYLAWS.**

11.1 Joint Filing of Bylaws for FERC Approval. These Bylaws shall be jointly filed with FERC for its approval within 20 calendar days, or as soon thereafter as practicable, of the date of these Bylaws. Such filing shall be undertaken by at least two Applicants, one which must be an investor-owned utility and at least one other Applicant which must be in any other category of membership.

11.2 Notice of Joint Filing and Opportunity of Each Category of Membership to Participate. Each Applicant which has executed these Bylaws shall be provided a notice of such joint filing and the opportunity for each category of membership to appoint a representative for such membership category to participate in such joint filing. Each category of membership which participates in such joint filing with FERC shall bear its respective costs resulting from such joint filing.

11.3 Bylaws Effective as to Applicants; Term of Bylaws; No FERC Jurisdiction Voluntarily Granted; Amendment or Termination of Bylaws.

11.3.1 Bylaws Effective as to Applicants. These Bylaws shall become effective as among the Applicants executing them when approvals required under Section 11.3.2 have been obtained; provided, that these Bylaws shall not become effective as to any Applicant if (i) the approval of that Applicant's right of unilateral withdrawal requested in accordance with Section 11.4.1 is not allowed by FERC, absent that Applicant's consent, or (ii) any terms, conditions or requirements imposed by FERC are found unacceptable by the Applicant.

11.3.2 Bylaws Effective When Accepted By FERC Without Change or Condition. These Bylaws shall become effective as among the Applicants executing them when the Bylaws are accepted for filing by FERC, without changes or conditions. If upon filing of these Bylaws in accordance with Sections 11.1 and 11.2 FERC orders a hearing on or involving these Bylaws, the Bylaws shall not become effective until the date when a final non-appealable order is issued by FERC accepting, confirming or approving these Bylaws without changes or new conditions.

11.3.3 Changes or Conditions Imposed by FERC. Any changes or conditions to the Bylaws, as then in effect, which are imposed by FERC or any other Regulatory Authority or by a court shall be grounds for immediate withdrawal by any nonconsenting Member.

11.5 No FERC Jurisdiction Voluntarily Granted. Nothing contained in these Bylaws shall give FERC jurisdiction over those Members not otherwise subject to such jurisdiction or be construed as a grant of jurisdiction over any Member by any Regulatory Authority not otherwise having jurisdiction by law.

SWRTA

WRTA

17. FERC REVIEW.

17.1 Application for Approval. Following receipt of a letter from the WSCC in substantially the form set forth in attached Exhibit A, this Governing Agreement shall be filed with the FERC by PacifiCorp. In such filing the FERC shall be requested to:

(a) Find that this Governing Agreement, as written, is in the public interest;

(b) Expressly approve the provisions of this Governing Agreement, related to obtaining membership (Subsection 3.1), termination of membership (Subsections 3.4 and 3.5) and termination of the Association (Section 18) and find that the FERC notice provisions provided for therein shall be effective to initiate membership, terminate membership and terminate the Association consistent with the FPA and the FERC's rules and regulations thereunder; and

(c) Expressly approve the dispute resolution provision of Section 12 and the procedures for FERC appeal set forth therein.

17.2 Absence of FERC Approval. If the FERC issues an order requiring material changes to this Governing Agreement, or omitting any of the findings or approvals set forth in Subsection 17.1, this Governing Agreement shall have no further force or effect.

FILING BYLAWS WITH FERC

11.3.4 Term of Bylaws. These Bylaws shall continue in effect until terminated by vote of the Board of Directors.

306 of the FPA may or may not have to change rates or rate methodologies established pursuant to an order entered pursuant to Section 211 of the FPA; provided that changes under either (i) or (ii) above result in rates that are consistent with the standards of Section 212 of the FPA.

14.5 This Governing Agreement does not replace, modify, supersede or limit any contract, decisions of regulatory agencies or courts of law, or other legally-enforceable entitlement, rights or obligations of any Member, or limit a Member's liability under any contract, except as specifically provided herein.

18. TERMINATION OF ASSOCIATION.

The Association shall automatically go out of existence and this Governing Agreement shall have no further force or effect at such time, more than one year following the effective date of this Governing Agreement that a majority of the board agrees that there are too few Members for effective operation of the Association. Such termination shall be effective upon the Secretary providing written notice of such termination to the FERC.

19. EFFECT OF BYLAWS:

19.1 Except as expressly provided herein, no Member waives any right that it would otherwise have had it not joined SWRTA but instead proceeded to FERC directly or was the respondent in a FERC proceeding. All Members are specifically presumed to have preserved their rights in a dispute to assert to both an Arbitrator or FERC that a proposed transaction does not meet the standards of the FPA.

19.2 Except as expressly provided herein, these Bylaws specify procedural requirements only and do not constitute a requirement or consent by any Member to any substantive terms or conditions of public utility service.

19.3 These Bylaws shall not, in and of themselves, be construed as a tariff, rate schedule or service agreement providing for transmission service. These Bylaws shall not be construed as an agreement of any Member to provide transmission services of a type or under circumstances that would not be required by FERC pursuant to FPA Sections 211 or 212.

19.4 Nothing in these Bylaws shall be construed as affecting the right of any Member in regard to transmission services not being provided pursuant to an order issued pursuant to Section 211 of the FPA to unilaterally seek to change rates or rate methodologies. Nothing in these Bylaws shall be construed as affecting the right any Member subject to FERC jurisdiction may have to unilaterally make application to FERC under Sections 205, 206 and 306 of the FPA for a change in rates or rate methodologies established pursuant to an order entered pursuant to Section 211 of the FPA or the right any Member not subject to FERC jurisdiction under Sections 205, 206 and 306 of the FPA may have to change rates or rate methodologies pursuant to an order entered pursuant to Section 211 of the FPA; provided that such changes result in rates that are consistent with the standards of Section 212 of the FPA.

19.5 These Bylaws do not replace, modify, supersede or limit any contract, decisions of regulatory agencies or courts of law, or other legally-enforceable entitlement rights or obligations of any Member, or limit a Member's liability under any contract, except as specifically provided

14. EFFECT OF GOVERNING AGREEMENT.

14.1 Except as expressly provided for herein, no Member waives any right that it would otherwise have had it not joined the Association but instead proceeded to the FERC directly or was the respondent in a FERC proceeding. Except as expressly provided for herein, all Members are specifically presumed to have preserved their rights to assert to both an Arbitrator and the FERC on appeal any argument or position which they could have presented to the FERC, absent this Governing Agreement, pursuant to Section 211 of the FPA.

14.2 Except as expressly provided herein, this Governing Agreement specifies procedural requirements only and does not constitute a requirement or consent by any Member to any substantive terms or conditions of public utility service.

14.3 This Governing Agreement shall not, in and of itself, be construed as a tariff, rate schedule or service agreement providing for transmission service. This Governing Agreement shall not be construed as an agreement of any Member to provide transmission services of a type, under circumstances or pursuant to rates, terms and conditions that would not be required by the FERC pursuant to FPA Sections 211 or 212.

14.4 Nothing in this Governing Agreement shall be construed as affecting the right of any Member in regard to transmission services provided pursuant to a section of the FPA other than Section 211 to unilaterally seek to change rates or rate methodologies. Nothing in this Governing Agreement shall be construed as establishing or affecting (i) any right a Member subject to FERC jurisdiction under Sections 205, 206 and 306 of the FPA may or may not have to unilaterally make application to FERC under such sections for a change in rates or rate methodologies established pursuant to an order entered pursuant to Section 211 of the FPA or (ii) any right a Member not subject to FERC jurisdiction under Sections 205, 206 and

13. LIMITATIONS OF LIABILITY OF MEMBERS AND MEMBER'S DIRECTORS, EMPLOYEES AND REPRESENTATIVES: The obligations and liabilities of each Member under these Bylaws are intended to be several and not joint or collective and nothing in these Bylaws shall be construed to create a joint venture, trust or partnership, or to impose a trust or partnership obligation or liability on or with regard to any of the Members. Neither the members of the board of directors of any Member nor any officer, employee or agent of any Member shall be individually liable with respect to any actions taken or not taken by the Board of Directors, the Planning Committee or any other committee established under these Bylaws.

20. MISCELLANEOUS PROVISIONS:

20.1 Limitation on Liability

It is the express intent, understanding and agreement of the Members that the remedies for nonperformance expressly included in Section 11.4 hereof shall be the sole and exclusive remedies available hereunder for any nonperformance of obligations under these Bylaws. Subject to any applicable state or federal law which may specifically limit a Member's ability to limit its liability, no Member, its directors, members of its governing bodies, officers or employees shall be liable to any other Member or Members for any loss or damage to property, loss of earnings or revenues, personal injury, or any other direct, indirect, or consequential damages or injury which may occur or result from the performance or nonperformance of these Bylaws, including any negligence arising hereunder.

20.2 No Third Party Beneficiaries

Nothing in these Bylaws shall be construed to create any duty to, any standard of care with reference to, or any liability to any third party.

16. MISCELLANEOUS PROVISIONS.

16.1 Limitation on Liability. It is the express intent, understanding and agreement of the Members that the remedies for nonperformance expressly included in Subsections 3.4 and 12.4 of this Governing Agreement shall be the sole and exclusive remedies available under this Governing Agreement for any nonperformance of obligations under this Governing Agreement. Subject to any applicable state or federal law which may specifically limit a Member's ability to limit its liability, no Member, its directors, members of its governing bodies, officers or employees shall be liable under this Governing Agreement to any other Member or Members for any loss or damage to property, loss of earnings, revenues, personal injury, or any other direct, indirect, or consequential damages or injury which may occur or result from the performance or nonperformance of this Governing Agreement, including any negligence arising thereunder. Nothing in this Governing Agreement is intended to expand or limit any Member's liability pursuant to any law, regulation, contract or agreement other than this Governing Agreement.

16.2 No Third-Party Beneficiaries. Nothing in this Governing Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any third party.

11.3.5 Board Approval to File with FERC Amendment or Termination of Bylaws. No filing with FERC to amend or terminate these Bylaws shall be made by any Member(s) except upon 2/3 majority vote of the Directors of each membership category of the Board of Directors. Any amendment or change in these Bylaws that is subject to FERC jurisdiction with regard to any Member shall not become effective until the date when a final non-appealable order is issued by FERC accepting, confirming or approving the amendment or change without new conditions or changes. Any changes or conditions imposed by FERC or any other Regulatory Authority or by a court shall be grounds for immediate withdrawal by any nonconsenting Member.

11.3.6 Revision of Appendices or Exhibits Not an Amendment to Bylaws. Revisions in accordance with these Bylaws of any appendix or exhibit to these Bylaws shall not constitute an amendment of the Bylaws or require filing with or approval of FERC.

17. AMENDMENTS:

These Bylaws may be amended at any annual or special meeting of the Members by a vote of seventy-five percent (75%) of the Members in each Member Class; or by action taken without a meeting if set forth in writing and duly signed by seventy-five percent (75%) of the Members in each Member Class.

16. MEMBER COSTS:

The initial formula for allocation of administrative costs of SWRTA shall be as shown in Appendix A, attached hereto. The allocation formula may be changed upon a majority vote of the Members taken pursuant to Section 12 hereof. Should such a change be approved, Appendix A shall be revised to so reflect the newly approved allocation formula.

APPENDIX A

The administrative costs of SWRTA shall be allocated among the Members as follows:

A.1 Annual Membership Fee

Each Member shall pay to the Treasurer within sixty (60) days following the annual meeting an annual membership fee as approved pursuant to the budget process set forth in Sections 14.4 and 15.5 hereof. The annual membership fee shall cover all costs incurred for duplication and distribution of SWRTA materials and reports.

A.2 Other Administrative Costs

Other costs approved pursuant to the budget process set forth in Section 14.4 and 15.5 hereof shall be allocated among and paid by Members as follows:

A.2.1 For Members that sold energy over the prior year
A = [(OAC - [(OAC/TM) x NLM)) x KWH)/TKWH, where
A = Allocation of Other Administrative Costs
OAC = Other Administrative Costs
TM = Total Number of Members
NLM = Members that did not sell energy over the prior year
KWH = Member's energy sold for prior year
TKWH = SWRTA Members' total energy sold for prior year

A.2.2 For Members that did not sell energy over the prior year
A = OAC/TM, where
A = Allocation of Other Administration Costs
OAC = Other Administrative Costs

15. AMENDMENTS.

Subject to approval of the FERC, this Governing Agreement may be amended only by the Members at any annual or special meeting.

8. MEMBER COSTS.

8.1 Administrative Costs. Unless and until the Board establishes a different allocation formula, the administrative costs of the Association, other than planning costs, shall be allocated among Members as follows:

8.1.1 25% of the total costs shall be allocated among the Members, other than Commissions, on a per capita basis, and

8.1.2 75% of the total costs shall be allocated among the Members in proportion to their total revenues from the sale of electricity.

8.2 Planning Costs. The costs of planning studies or other activities not undertaken in response to a request for transmission services, if undertaken by the Association, shall be allocated by the Board with the expectation that planning costs associated with particular projects shall be generally allocated among the Members benefitting from such activities in proportion to the amounts of transmission capacity in megawatts desired by each participating Member. Specific activities and cost allocations may be memorialized in separate agreements among the participating Members.

more than sixty (60) days before such meeting. Such notice shall state the time and place of the meeting and the meeting agenda.

12.3 Voting

Each Member shall be entitled to one (1) vote upon each matter submitted to a vote at a meeting of the Members. Except for Bylaws amendments and actions taken without a meeting, all questions shall be decided by a vote of two-thirds (2/3) of the Members in each Member Class present at the meeting after a quorum has been determined to be present.

12.4 Quorum

A majority of the Members eligible to vote within each Member Class shall constitute a quorum necessary for the transaction of business other than Bylaws amendments at any annual or special meeting of the Members. Those Members present may adjourn from time to time until a quorum shall be present with no further notice of the meeting required.

12.5 Action Taken Without a Meeting

Any action which may be taken at a meeting of the Members may be taken without a meeting if noticed to the membership and a writing setting forth and approving the action taken is signed by seventy-five percent (75%) of the Members entitled to vote on such action in each Member Class, and such action shall be effective on the date designated therein or on the date of the last signature if no such date is designated.

12.6 Special Meetings

A special meeting of the Members shall be held whenever called by the Board. The Board may call a special meeting whenever it deems it appropriate and must call a special meeting whenever requested by at least twenty-five percent (25%) of the Members of each class. Notice of each special meeting shall be given as provided in Section 12.2 hereof.

4.4 Quorum. A majority of the total number of Members with voting rights shall constitute a quorum necessary for the transaction of business at any annual or special meeting of the Members. Those Members present may adjourn from time to time until a quorum is present with no further notice of the meeting required.

charge and supervision of the books and records of SWRTA. The Secretary shall sign all papers pertaining to SWRTA as may be authorized or directed by the Board. The Secretary shall serve all notices required by law, regulation and these Bylaws, including notices of meetings, and shall make a full report of all matters and business pertaining to the office to the Members at the annual meeting. The Secretary shall make all reports required by law and regulation and shall perform such other duties as may be required of the Secretary by these Bylaws or the Board. An Assistant Secretary, if any, shall perform the duties of the Secretary during the absence or disability of the Secretary.

15.5 Duties of Treasurer: The Treasurer shall annually develop and propose a budget and annual membership fee to the Board for its approval pursuant to Section 14.4 hereof, which budget shall include all costs of administration of SWRTA as well as any other anticipated costs to be allocated to the Members, and shall perform such other duties with respect to the finances of SWRTA as may be prescribed by the Board. An Assistant Treasurer, if any, shall perform the duties of the Treasurer during the absence or disability of the Treasurer.

15.6 Duties of Manager: The Manager shall perform such duties and shall exercise such authority as the Board may from time to time vest.

15.7 Compensation: The salary, compensation and other benefits of the Manager and any other staff shall be fixed by the Board, provided that no Director or officer shall receive any compensation or other benefits.

12. MEETINGS OF MEMBERS:

12.1 Annual Meeting

A meeting of SWRTA Members shall be held annually. The annual meeting of the Members shall be held on a date and at a time and place fixed by the Board. Each Member shall designate a representative and alternate to receive notices of the annual meeting and to vote upon issues presented at such meeting.

12.2 Notice of Meeting

Written notice of every annual meeting of the Members shall be prepared and mailed to the last known post office address of each Member's

the office to the Members at the annual meeting. The Secretary shall make all reports required by law and shall perform such other duties as may be requested by the Board.

7.5 Duties of Treasurer. The Treasurer shall perform such duties with respect to the finances of the Association as may be prescribed by the Board.

7.6 Duties of Manager. The Manager shall perform such duties and shall exercise such authority as the Board may from time to time vest. The Manager shall put in place and maintain Association newsletters and/or an electronic bulletin board sufficient to keep Members timely informed of events related to Members' activities carrying out the purposes of this Governing Agreement.

7.7 Compensation. The salary, compensation and other benefits of the Manager and any other staff shall be fixed by the Board. No member of the Board shall receive any compensation or other benefits.

4. MEETINGS OF MEMBERS.

4.1 Annual Meeting. A meeting of the Members shall be held within 60 days of the effective date of this Governing Agreement on a date established by PacifiCorp, and thereafter at least annually, within the Western Interconnection on a date and at a time and place fixed by the Board.

4.2 Notice of Meeting. Written notice of every meeting of the Members shall be prepared and mailed to the last known address of each Member not less than 21 nor more than 60 days before such meeting. Such notice shall state the time and place of the meeting and the meeting agenda.

4.3 Voting. Each Member, other than a Commission, shall be entitled to one vote upon each matter submitted to a vote at a meeting of the Members. Except in regard to the election of Directors, all matters requiring Membership approval shall require the affirmative vote of two-thirds of the Members of each voting Membership classification present at the meeting in order to be adopted.

9.4 **Voting on Planning Committee.** Decisions of the Planning Committee shall be determined based upon three of the four categories of membership affirmatively voting with respect to any issue before the Planning Committee with each category's vote determined by a 2/3 majority vote of the Members of each category of membership described in Section 8.7.1 attending the Planning Committee meeting; provided that if there are no Members on the Planning Committee from a category of membership attending a meeting of the Planning Committee, such category of membership shall be deemed to have voted affirmatively with respect to any issue subject to a vote at such meeting. The ex officio members of the Planning Committee shall have no voting rights on the Planning Committee. Each category of membership on the Planning Committee should collectively have knowledge in the planning or operation of transmission systems or generation.

9.5 **Regular Meetings; Notice; Minutes.** The Chair of the Planning Committee shall call regular meetings of the Committee. The Chair shall promptly call a meeting of the Planning Committee at the request of a majority of representatives on the Planning Committee, or their designated alternates. Adequate notice shall be given of each Planning Committee meeting to all Planning Committee members at least four weeks in advance unless otherwise agreed to or waived by at least 2/3 of all Members on the Planning Committee. The Secretary shall prepare formal minutes of each meeting. Such formal minutes shall be prepared and typed for each meeting. Copies of such written minutes shall be corrected and approved by the Planning Committee at its next meeting and submitted to the Board.

9.6 **Officers of Planning Committee.** Officers of the Planning Committee shall be elected by the representatives of the Members of the Planning Committee. The officers of the Planning Committee shall be a Chair, Vice-Chair, and Secretary. The terms of each such office shall be determined by the representatives of the Members of the Planning Committee.

9.7 **Subcommittees.** Subcommittees of the Planning Committee may be established from time to time by the Chair, subject to confirmation by the Planning Committee, and shall consist of such Members as may be appointed by the Chair and confirmed by the Planning Committee.

9.8 **Develop Procedures for Notice of Transmission Requests.** Each Member shall comply with procedures to be developed by the Planning Committee which shall provide for each Member to receive a timely notice of a request for transmission service pursuant to Section 5 and the applicable Appendix A of these Bylaws.

9.9 **Develop Procedures for Notice of Execution of Transmission Service Contracts.** Each Member shall comply with procedures to be developed by the Planning Committee which shall provide for each Member to receive a timely notice of the execution of a contract providing transmission service by a Member whether or not such contract was executed in accordance with these Bylaws.

14.9 Funds

The Board shall have power to select one (1) or more banks or other financial institutions to act as depositories of the funds of SWRTA, and to determine the manner of receiving, depositing, and disbursing the funds of SWRTA, the form of checks, and the person or persons authorized to sign checks, with the power to change such banks and the person or persons authorized to sign checks and the form thereof at will.

15. OFFICERS AND MANAGER:

15.1 Election of Officers

At each annual meeting of the Board of Directors, the Board shall elect a President, a Vice President, a Secretary and a Treasurer. The Board may elect one (1) or more Assistant Secretaries and Assistant Treasurers, which need not be Directors, as and when it may deem necessary. Except for Assistant Secretaries and Assistant Treasurers, officers must be Directors of SWRTA and may serve a maximum of three (3) consecutive years in office. An officer may be removed by the Board whenever in its judgment the best interests of SWRTA will be served thereby. If any vacancy shall occur among the officers of SWRTA, it shall be filled by the Board at its next regular meeting following the vacancy.

15.2 Duties of President

The President shall (i) preside over all meetings of SWRTA and of the Board; (ii) call special meetings of the Board; and (iii) perform all duties that may be required of him or her by these Bylaws or the Board.

15.3 Duties of Vice President: In the absence or disability of the President, the Vice President shall perform the duties of the President.

15.4 Duties of Secretary: The Secretary shall attend all meetings of the Board and all meetings of the Members and record all votes and keep minutes of all proceedings. The Secretary shall keep a complete record of all meetings of SWRTA Members and of the Board and shall have general

disputes that an Arbitrator or facilitator is considered to be qualified to decide or by subregional areas concerning which an Arbitrator or facilitator has expertise. All arbitrator names supplied by the Arbitration Committee pursuant to Part 12.2.2 shall be taken at random from the Board-approved list or, at the election of all disputing Members involved in a dispute, subdivisions of that list.

7. OFFICERS AND MANAGER.

7.1 Election of Officers. At each annual meeting of the Board of Directors, the Board shall elect a President, a Vice President, a Secretary and a Treasurer. The President and Vice President shall be chosen from the Directors of the Association. An officer may be removed by the Board whenever in its judgment the best interests of the Association will be served thereby. If any vacancy shall occur among the officers of the Association, it shall be filled by the Board of Directors at its next regular meeting following the vacancy.

7.2 Duties of President. The President shall: (i) preside over all meetings of the Association and the Board; (ii) call special meetings of the Board; and (iii) perform all duties that may be reasonably required by the Association or the Board.

7.3 Duties of Vice President. In the absence or disability of the President, the Vice President shall perform the duties of the President.

7.4 Duties of Secretary. The Secretary shall attend all meetings of the Board and all meetings of the Members and record all votes and keep a complete record of all meetings of the Association and of the Board and shall have general charge and supervision of the books and records of the Association. The Secretary shall sign all papers pertaining to the Association as may be authorized or directed by the Board. The Secretary shall serve all notices required by law and by this Governing Agreement including notices of meetings and shall make a full report of all matters and business pertaining to

(vi) Compile and update on a biennial basis, the Members' transmission and resource plans into a consolidated document;

(vii) Make recommendations, as may be appropriate, to the Members and the Board regarding the adequacy of planned inter- and intra-control area transmission transfer capabilities to meet the reasonable needs of Members based upon the Long Term Transmission Plans submitted by the Members;

(viii) Ensure that all analyses and information prepared by, or provided to, the Planning Committee are available to all Members;

(ix) Develop new Appendices A as required for new Members not covered by existing Appendices A;

(x) Establish as soon as practicable an electronic bulletin board to permit dissemination of WATSCO-related information and notices (excluding written notices) required under these Bylaws;

(xi) Modify, when appropriate, the requirements of the Long Term Transmission Plan set forth in Exhibit A;

(xii) Develop rules and guidelines regarding notification of Members of the execution of contracts related to these Bylaws, as referenced in Appendix A;

(xiii) May develop rules and guidelines regarding (a) what constitutes a "substantial change" in a service request and (b) reasonable time periods related to competitive bidding process, each as referenced in Appendix A; and

(xiv) Perform such other functions and duties as may be provided in these Bylaws and undertake other activities as directed by the Board.

9.2 **Meetings Open to Members.** Meetings of the Planning Committee shall be open to any Member and any Member may make recommendations and presentations to the Planning Committee. The Planning Committee may make decisions specified in these Bylaws and recommendations to the Board.

9.3 **Membership on Planning Committee.** Each Member may appoint one duly authorized representative to the Planning Committee and shall designate such individual as its representative on the Planning Committee by giving notice to the Secretary of the Planning Committee. Each Member or group of Members may, by giving notice to the Secretary of the Planning Committee, designate an alternate or alternates to vote or act as its or their, as the case may be, representative on the Planning Committee in the absence of the regular member, or to vote or act on specified occasions with respect to specified matters, such notice is to be effective upon receipt by the Secretary of the Planning Committee. As provided in Section 8.1.2, the Board of Directors may designate from time to time no more than two representatives from regulatory and/or governmental agencies from each State in which a Member is subject to such regulatory and/or governmental agency to be ex officio members of the Planning Committee.

Such bonds, unless cash security is given, shall be furnished by a responsible bonding company and approved by the Board and the cost thereof shall be an administrative cost of SWRTA. The Board shall provide for the adequate insurance of the property of SWRTA, or property which may be in the possession of SWRTA and, in addition, adequate insurance for personal and public liability. The cost for such insurance shall also be an administrative cost of SWRTA.

14.7 Committees

In addition to the Planning Committee, which is a standing committee of SWRTA as set forth in Section 6 hereof, the Board may form or establish and dissolve other committees as it deems necessary to carry out the business of SWRTA. The Board shall set forth the duties and responsibilities of each such committee in writing at the time of the creation of the committee. Each such committee shall be subject at all times to control and direction of the Board. Copies of the minutes of all committee meetings, including meetings of the Planning Committee, shall be mailed to all Directors. Commissions may appoint staff members to serve as ex officio members of the Planning Committee and any other committee established by the Board. Such ex officio members may attend and participate in all committee meetings, but shall not have a right to vote on matters coming before the committees.

14.8 Qualified Arbitrators

The Board shall establish and from time to time update a list of Arbitrators who are familiar with and knowledgeable about the policies and criteria of WSCC, transmission systems, and federal statutory and regulatory requirements, and who meet other Board-determined qualifications to render decisions for disputes between or among Members of SWRTA. The list of Arbitrators may be segmented into specific types of disputes that an Arbitrator is considered to be qualified to decide, at the discretion of the Board.

6.7 Arbitration Committee. The Board shall appoint an Arbitration Committee consisting of one Board member from each of the three voting Membership classifications. The Arbitration Committee shall have the responsibilities described in Subsection 6.9 and Part 12.2.2 and shall also, from time to time, review the arbitration procedures set forth in this Governing Agreement and consider proposed changes to be presented to the Board. Members of the Arbitration Committee shall disqualify themselves from participating in any dispute involving such member's employer and any member so disqualified shall be replaced by the President or Vice-President for purposes of the dispute in question.

6.8 Other Committees. The Board may authorize such additional committees as it deems necessary to carry out the business of the Association. The Board shall set forth the duties and responsibilities of each such Committee in writing at the time of the creation of the Committee. Each such Committee shall be subject at all times to control and direction of the Board. Copies of the minutes of each Committee meeting, including Planning and Arbitration Committee meetings, shall be mailed to all Directors and any Members requesting copies.

6.9 Qualified Arbitrators. The Arbitration Committee shall propose and the Board shall establish and from time to time update, a list of qualified Arbitrators and facilitators. Qualified Arbitrators shall be knowledgeable in matters regarding the planning and operation of interconnected electric systems in the Western Interconnection and in regulatory policies and requirements. Consistent with the resources available to it, each Member shall make its employees available for reasonable periods to serve as Arbitrators and facilitators. The list of Arbitrators and facilitators may be subdivided by the Arbitration Committee into specific types of

(viii) Provide for the preparation and distribution of the minutes of all Board meetings to Members;

(ix) Provide for the auditing of the use and management of moneys budgeted as provided by these Bylaws; and

(x) Perform such other functions and duties as may be provided for in these Bylaws, or as may otherwise be appropriate.

9. PLANNING COMMITTEE: The Planning Committee is primarily established to provide a forum for the development of fully coordinated plans for regional and subregional transmission use and additions.

9.1 Powers and Duties of the Planning Committee. The Planning Committee shall have the following powers and duties:

(i) In accordance with Section 4.5, ensure that a repository of system data is available from which Members may obtain information necessary to conduct coordinated transmission planning. The Committee shall establish or designate a data base, including adequate documentation of assumptions, that may be used for modeling of the Members' electrical system. Consistent with Section 4, this data base shall include detailed information about the existing and planned transmission system and generating resource operating data sufficient to allow any Member to model and determine the transfer capability with respect to a proposed transmission service request or project. Members shall provide the Planning Committee with adequate electrical system data, system operating assumptions, and other information which is reasonably necessary in order to permit other Members to evaluate the availability of requested transmission service or the need for and impacts of new transmission facilities. To the maximum extent feasible the Planning Committee shall provide that the information be supplied in the form and format required for other purposes so as to avoid unnecessary duplication. The Planning Committee shall take those steps needed to ensure that the transmission facility planning needs of Members are adequately addressed by the data base.

(ii) Facilitate the coordinated transmission planning activities of Members consistent with Section 4.8;

(iii) Encourage all Members to seek membership in WSCC in order to maximize consistency of data, minimize disputes over access to data and models, and reduce the need for duplicative study efforts;

(iv) Act as an interface with WSCC and other RTGs on matters related to coordinated planning and planning data;

(v) Establish, upon request of any Member and after notice thereof to all other Members, a Zone of Reasonableness for that Member's and all Members' similar planning assumptions which are adopted through regulatory proceedings; the "Zone of Reasonableness" is for the purpose of developing an appropriate deviation from adopted planning assumptions to reflect changes in circumstances affecting such planning assumptions which may occur during the time interval between applicable regulatory proceedings;

14.2 Selection of Manager and Agents

The Board may select and employ a Manager, and fix the compensation of such Manager. The Board may terminate the employment of the Manager with or without cause at any time. The Board shall also have authority to retain agents to provide defined services.

14.3 Membership

The Board shall review and act upon applications for membership in SWRTA pursuant to Section 11.1 hereof. The Board shall also receive notices of withdrawal from membership pursuant to Section 11.3 hereof and shall act on suspensions or terminations of membership pursuant to Section 11.4 hereof.

14.4 Budgets

The Board shall annually establish and recommend a budget for Member approval at the annual meeting, which budget shall be developed by the Treasurer pursuant to Section 15.5 hereof and shall include an annual membership fee covering all costs of administration for SWRTA as well as any other anticipated costs to be allocated to the Members. Such budgets shall be established and recommended at least ninety (90) days prior to the annual meeting. The Board shall notify all Members in writing of the recommended budget and annual membership fee no later than sixty (60) days prior to the annual meeting.

14.5 Accounting System and Audit

The Board shall install and maintain an adequate system of accounts and records. At least once each year the books and accounts of SWRTA shall be audited by an independent certified public accounting firm and the report of such audit shall be made at the next annual meeting of the Members.

14.6 Bonds and Insurance

The Board shall require that adequate bonds be provided covering the manager and all directors, officers, agents, and employees of SWRTA.

6.3 Budgets. The Board shall periodically establish and approve a budget which includes all costs of administration for the Association as well as any anticipated planning costs to be allocated to the Members. Such budgets shall be established and approved not less than annually.

6.4 Accounting System and Audit. The Board shall install and maintain an adequate system of accounts and records. At least annually, the books and accounts of the Association shall be audited by a certified public accountant and the report of such audit shall be made at the next annual meeting of the Members.

6.5 Committees. The Board shall create and, except for the Planning and Arbitration Committees, terminate Committees as it deems appropriate. Membership on all Committees appointed by the Board shall be allocated among membership classifications and geographic regions on generally the same proportional basis as required for Board membership. In regard to each Committee, the Board shall appoint a cochairperson from each of the three membership classifications. The three cochairpersons shall alternate responsibility for chairing the committee as among themselves so that cochairpersons representing any membership classification shall not have such responsibility for more than ten months during any 24-month period. Cochairpersons shall serve terms of three years unless a shorter term is established by the Board. Reasonable advance notice of all Committee meetings shall be given to all Members. Attendance at all Committee meetings shall be open to any Member. Matters coming before Committees shall be adopted only by a majority vote, in each of the three voting membership classifications, of Committee members present.

6.6 Planning Committee. The Board shall appoint a Planning Committee whose function is described in Subsection 9.1. Three persons, one person from each of the Transmission-Dependent Utility, Nonutility Supplier and Commission classifications, shall be designated by the Planning Committee to serve as liaisons with the planning committees of the WSCC and other planning bodies.

8.14 **Board Officers.** Immediately following the adjournment of each annual meeting, the Board of Directors shall meet to elect a President, Vice President, Secretary and Treasurer provided that the offices of the Secretary and Treasurer may be combined in one person. The President shall preside at all meetings of the Board. In case of the absence or disability of the President, the duties of that office shall be performed by the Vice President.

8.15 **President Appoints Committees.** The President may, within the Board approved budget limits and with the approval of a 2/3 majority of the Board, appoint committees, hire staff and enter into contracts on behalf of WATSCO as appropriate.

8.16 **Annual Meeting of the Board of Directors and the Members.** The Board shall determine the date and location of each annual meeting of WATSCO. At each annual meeting, all WATSCO Members may review and comment on the proposed budget for the coming year and consider any Board proposed changes to the Bylaws as necessary. The first meeting shall be as soon as practicable following the effective date of these Bylaws. Subsequent annual meetings shall be at a time and location determined by the Board. Except as otherwise determined by the Board of Directors, the budget shall be adopted by the Board of Directors at the annual meeting.

8.17 **Special Board of Directors Meeting.** The President, the Vice President or a majority of the Board of Directors may call a special meeting of the Board of Directors. Except as otherwise provided by applicable law, written notice of the proposed agenda, location, date and time of the special meeting shall be provided to each Member and ex officio member at least one business day prior to the date of such special meeting.

8.18 **Board Duties, Powers and Responsibilities.** The Board of Directors shall have the following duties, powers and responsibilities:

(i) Adopt rules, regulations and policies to implement and accomplish the purposes and provision of these Bylaws as necessary;

(ii) Adopt lists of qualified arbitrators consistent with Section 10;

(iii) Exercise general supervision over the Planning Committee and other committees established pursuant to these Bylaws, and review, discuss and attempt to resolve any disputes within any such committee;

(iv) On request of any Member, review, discuss and attempt to resolve any disputes among any of the Members relating to WATSCO not otherwise covered by these Bylaws;

(v) Review, modify and approve or disapprove an annual budget and revisions thereof prepared and submitted with respect to WATSCO;

(vi) Consider any matters relating to the general supervision of WATSCO proposed by any Member;

(vii) Delegate any of its duties or responsibilities to the Planning Committee or any committee established pursuant to these Bylaws;

13.8 Quorum and Voting

A majority of the Directors in office from each Member Class shall constitute a quorum necessary to the transaction of business at any regular or special meeting of the Board, but if less than a quorum is present, those Directors present may adjourn the meeting from time to time until a quorum shall be present with no further notice of the meeting required. All questions shall be decided by a vote of two-thirds (2/3) of the Directors from each Member Class present at a meeting, rounded up to the next whole number of Directors, after a quorum has been determined to be present, except as otherwise provided in these Bylaws.

13.9 Action Taken Without a Meeting

Any action which may be taken at a meeting of the Board, or of a lawfully constituted committee thereof, may be taken without a meeting if noticed to the membership and set forth and approved by a writing signed by two-thirds (2/3) of the Directors or committee members from each Member Class, and such action shall be effective on the date on which the last signature is placed on such writing, or such earlier effective date as is set forth therein.

Also See SWRTA § 12.5 in this Section

14. DUTIES OF DIRECTORS:

14.1 General Powers

The Board shall manage the business and affairs of SWRTA, and shall exercise all of the powers of SWRTA except such as are by law or these Bylaws conferred upon or reserved to the Members. The Board shall recommend any amendments to the Bylaws for approval by the Members and shall adopt such policies, rules, regulations, and actions not inconsistent with law or these Bylaws as it may deem advisable.

called by the President or Secretary in like manner and on like notice on the written request of any four Directors.

5.9 Quorum and Voting. Two-thirds of the Directors in each voting membership classification shall constitute a quorum necessary to the transaction of business at any meeting of the Board. All matters coming before the Board shall require the affirmative vote of two-thirds of those present from each voting class of Directors. By providing written notice to the President, a Director may designate an alternate to attend any Board meeting and such alternate shall have full authority to act and vote in place of the absent Director.

5.10 Action Without a Meeting. Any action which may be taken at a meeting of the Board, or of a Committee, may be taken without a meeting if set forth and approved by a writing signed by all Directors or Committee members, and such action shall be effective on the date on which the last signature is placed on such writing, or such earlier effective date as is set forth therein.

6. DUTIES OF DIRECTORS.

6.1 General Powers. The Board shall manage the business and affairs of the Association, and shall exercise all of the powers of the Association except such as are by law or this Governing Agreement conferred upon or reserved to the Members. The Board shall recommend any amendments to this Governing Agreement for approval by the Members and may adopt such policies, rules, regulations, and actions which are consistent with law and this Governing Agreement as it may deem advisable.

6.2 Selection of Manager and Agents. The Board shall select and employ a Manager and fix the compensation of such Manager. The Board may terminate the employment of the Manager with or without cause at any time. The Board shall also have authority to authorize the employment of other staff members or retain agents to provide defined activities and services.

8.8 **Initial Directors on Board.** The initial Directors on the Board of Directors for each membership category identified in Section 8.7.1 shall be elected or appointed by the respective Members of each such membership category which initially execute these Bylaws. Subject to Section 8.9, such Members in each such membership category shall identify the term of office for each Director in their respective membership category.

8.9 **Director's Term.** A Director's term shall be for three years provided that initially one third of the Directors in each membership category shall serve for one year, one third for two years, and one third for three years as determined in Section 8.8.

8.10 **Director's Election.** Except as provided in Section 8.8, Directors of each membership category defined in Section 8.7.1 shall be elected to the Board of Directors at the annual meeting by a majority vote of the current Members of that category of membership. If for any reason a category of membership does not or cannot elect a Director to all of its three Board of Director positions, the open Director position(s) shall remain vacant until the next annual meeting. Once filled, if a seat on the Board becomes vacant for any reason, a special election of the appropriate membership category shall be held to fill that vacant seat for the remainder of the unexpired term.

8.11 **Board Action.** All matters regarding WATSCO, including the annual budget and level and structure of Member dues, shall be decided by a 2/3 majority vote of the Directors of each category of membership currently holding office, unless otherwise provided in the Bylaws. With respect to the voting requirement identified as "2/3 majority vote of the Directors of each category of membership" as used in these Bylaws, such requirement means two of the three Directors of a category of membership must vote in the affirmative to carry a "yes" vote. If only one or two Director positions are filled regarding any category of membership, each Director of such category must vote in the affirmative to carry a "yes" vote. If no Director position of any membership category is filled, that category of membership shall be deemed to have voted "yes" with respect to any proposal being voted on by the Board.

8.12 **Amendments to These Bylaws.** Any amendments to the Bylaws must be approved by a 2/3 majority vote of each category of membership described in Section 8.7.1 of those Members in attendance at the meeting after recommendation by the Directors based upon a 2/3 majority vote of the Directors of each category of membership.

8.13 **Quorum and Voting of Board of Directors.** Two-thirds of the number of Directors currently holding office in each membership category shall constitute a quorum necessary to transact the business of the Board. All votes of the Board, whether taken by the Board as a whole or the membership category described in Section 8.7.1 shall be on a one-Director-one-vote basis.

the length of each Director's term by drawing lots within each Member Class, with one (1) Director from each Class serving a term of three (3) years, one (1) Director from each Class serving a term of two (2) years, and one (1) Director from each Class serving a term of one (1) year.

13.4 Removal of Directors and Vacancies

An individual Director may be removed from office by and at the discretion of the employer of the Director, or upon a vote of the Member Class represented by the Director to be removed. Additionally, a Director shall resign from office upon a change in place of employment. Whenever a vacancy occurs in the Board, other than from expiration of a term of office, such vacancy shall be filled by the alternate Director elected by the Member Class.

13.5 Annual Board Organizational Meeting

An organizational meeting of the Board shall be held within sixty (60) days following each annual meeting of the Members for the purpose of election of the officers of the Board for the upcoming year and to transact such other business as may properly come before the meeting.

13.6 Regular Meetings

A regular meeting of the Board of Directors, in addition to the Board's annual organizational meeting, shall be held at least one (1) time each year upon such notice and at such time and place as the Board may determine. The Board may also hold meetings by conference call.

13.7 Special Meetings

A special meeting of the Board shall be held whenever called by the President or, during the President's absence, by the Vice President, on notice delivered by first class mail at least fourteen (14) days prior to the meeting. Special meetings shall be called by the President or Secretary in like manner and on like notice on the written request of any Director.

nominated for a Director position if his or her election would violate the provisions of subparagraph 5.3. Except as applied to the initial Board, Directors shall be elected for terms of three years and until a successor is elected and qualified. The initial Board shall determine the length of each Director's term by drawing lots, with three Directors in each classification serving terms of three years, two Directors in each classification serving terms of two years, and two Directors in each classification serving terms of one year.

5.5 Removal of Directors and Vacancies. An individual Director may be removed from office by and at the discretion of a Member employing the Director or by majority vote of the classification of Members represented by the Director to be removed. Whenever a vacancy occurs, a Director's remaining term shall be filled by majority vote of the remaining Directors representing the class of Members whose Director's position became vacant until the next annual meeting at which time it shall be filled by a plurality vote of the classification represented by such Director.

5.6 Annual Board Organizational Meeting. A meeting of the Board shall be held at the conclusion of each annual meeting of the Members for the purpose of electing the officers of the Association for the upcoming year and to transact such other business as may come before the meeting.

5.7 Regular Meetings. Regular meetings of the Board, in addition to its annual meeting, shall be held upon such notice and at such time and place as the Board may determine. The Board may hold meetings by conference call.

5.8. Special Meetings. A special meeting of the Board shall be held whenever called by the President or, during the President's absence or disability, by the Vice President, on notice delivered by first class mail or facsimile at least seven days prior to the meeting. Special meetings shall be

GOVERNANCE

WATSCO

8. GOVERNANCE:

8.7 Board Composition.

8.7.1 Membership Categories. WATSCO shall be governed by a Board of Directors consisting of: (i) three Directors elected by investor-owned electric utility Members; (ii) three Directors elected by publicly-owned electric utility Members and joint powers agencies; (iii) three Directors elected by non-utility generator Members; and (iv) three Directors elected by the group of Members made up of Federal power marketing agencies/administrations, rural electrical cooperatives, state agencies owning transmission and any other entities which do not fall into the previous categories.

8.7.2 No Member Entitled to More Than One Director. No Member (including its affiliates or subsidiaries, or other entities under the control of such Member) shall have more than one Director on the Board.

Members whose activities in WATSCO are actively managed and directed by the same entity shall have no more than one Director on the Board. If two or more Members (each of which has accepted a Director's position on the Board) report to the same entity but assert that their activities in WATSCO are not actively managed and directed by such entity, any Member may request, in writing, such Members obtain from such entity a certified resolution or other suitable document which states that such Members' activities in WATSCO are not actively managed and directed by such entity. If no such resolution or document is promptly provided to such requesting Member, then the Directors of the Members under the common control of such entity shall immediately resign.

If any member of a joint powers agency or a rural electrical cooperative is a Member and shall have a Director, its joint powers agency or rural electrical cooperative, as the case may be, which is also a Member shall not be entitled to also have a Director.

8.7.3 Designation of Regulatory Representatives. The Board of Directors shall designate from time to time no more than two representatives from regulatory and/or governmental agencies from each State in which a Member is subject to such regulatory and/or governmental agency (at least one of which shall be from the State's public utility commission or its equivalent, and at least one of which shall be from an energy commission where such commission exists) to be ex officio members of the Board of Directors. Such representatives shall have those rights set forth in Section 8.1.2 but shall have no voting rights on the Board of Directors.

SWRTA

13. GOVERNANCE:

13.1 Board of Directors

SWRTA shall have a Board of Directors representing the Member Classes, comprised of not less than three (3) nor more than nine (9) Directors. Directors will be selected from within each Member Class, and each Class be entitled to have the following number of Directors:

Class 1 3 Directors

Class 2 3 Directors

Class 3 3 Directors

The number of Directors from each Member Class shall in no event be greater than the number of Members within the classification. Each Member Class shall also elect one (1) or more alternate Directors. Unless replacing an absent Director, an alternate Director shall have the right to attend Board meetings but shall have no right to vote or otherwise participate in the meetings.

See SWRTA § 2.12 in Definitions Section for description of Member Classes

13.2 Commission Participation as Ex-Officio Directors

Three (3) Directors may be selected from the total number of Commissions from states and provinces which have SWRTA Members to serve in an ex-officio status on the Board. Such ex-officio Directors shall be invited to attend and participate in all meetings of the Board and Committees, but shall not have a right to vote on matters coming before the Board or Committees.

13.3 Election of Directors

At each annual meeting of the Members, elections shall be held to fill a vacancy or vacancies on the Board. Directors and alternates will be elected from within each Member Class according to the voting procedures set forth in Section 12.3 hereof. Except as applied to the initial Board, Directors shall be elected for terms of three (3) years and shall serve until a successor is elected. The initial Board will determine

WRTA

5. GOVERNANCE.

5.1 Board of Directors. The Association shall have a Board of Directors comprised of 21 Directors. Directors shall be selected from among the three classifications of voting Members and each such classification shall be entitled to elect and be represented by the following number of Directors:

a. Major Transmitting Utilities 7

b. Transmission-Dependent Utilities 7

c. Nonutility Suppliers 7

5.2 Ex-Officio Directors. Commission Members may select up to three Directors to serve in an ex-officio status on the Board. Such ex-officio directors shall be invited to attend and participate in all meetings of the Board, and Committees, but shall not have a right to vote on matters coming before the Board or Committees.

5.3 Diversity of Directors. Each Director in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have his or her principal place of business in a different state or province, provided, however, two directors in each of these two classifications may be from California. No more than one Director in a classification may be employed by or be affiliated with any Member. At least three of the Directors in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have their principal place of business in the states of Texas, Arizona, New Mexico, California, Nevada or the states of Mexico and at least three of the Directors in the Major Transmitting Utilities and Transmission-Dependent Utilities classifications shall have their principal place of business in the states of Oregon, Washington, Idaho, Montana, Utah, Wyoming, Colorado or the provinces of British Columbia or Alberta.

5.4 Election of Directors. At each annual meeting of the Members, elections shall be held to fill any vacancies on the Board. Directors shall be selected from within each classification for each position by a plurality vote of the Members of that classification attending the meeting. No person may be

GOVERNANCE

10.21 **Enforcement of Binding Arbitration Proceeding Decision.** The decision of the Panel may be enforced by any court or agency having jurisdiction over the Party against which the decision is rendered.

10.22 **Extension of Time Periods By Mutual Agreement.** Any of the time periods provided in this Article 10 may be extended by mutual agreement of the Initiating Party, the Respondent, and all Indispensable Intervenors, with the approval of the Panel (if a Panel has been selected).

10.23 **Calendar Days.** Unless otherwise indicated, all time periods provided in these Bylaws refer to calendar days. For purposes of computing any time or notice period of this Appendix A, the period shall be so computed as to exclude the first day and include the last day; provided, that when the last day of any such period falls on Saturday, Sunday or a holiday under the laws of California, the computation shall omit such day and include the first business day thereafter.

10.24 **Settlement of Dispute During Binding Arbitration Proceeding.** A dispute may be settled at any time during the Binding Arbitration Proceeding, in part or in whole, by and between or among any of the Parties. Upon reaching a settlement, the settling Parties shall promptly advise the Panel and the Board or Board-appointed subcommittee, and shall file a copy of the settlement with those bodies. Non-settling Parties shall be unaffected by the settlement, and may proceed against other Parties as if no settlement had taken place, provided that the Panel may conduct a prehearing conference to consider the status of remaining issues and may allow the remaining Parties the opportunity to amend their filings as may be appropriate.

10.25 **Alternative Dispute Resolution.** Nothing in these Bylaws shall restrict any Member (in each Member's sole and absolute discretion) from undertaking, by mutual agreement with any other disputing Members, any alternative forms of dispute resolution they desire, including FERC adjudication proceedings.

more than 45 days) execute such contract and file it, including any supporting documentation, with FERC as a rate schedule or rate schedule amendment, as the case may be, if such a filing is required under the FPA. In such event, the Transmission Provider and the Transmission Requester shall both fully support such filing.

10.16.2 Type 2 Transaction. With respect to a Type 2 transaction, upon receipt of the contract executed by the Transmission Requester in accordance with Section 10.16, the Transmission Provider shall promptly (but no more than 45 days) execute such contract.

10.17 **Judicial Review of FERC Order.** A Member who is a party to a FERC proceeding initiated in accordance with Section 10.15 may seek judicial review of a FERC determination to the extent that judicial review is available by law.

10.18 **No Compensatory Damages Through Binding Arbitration Proceeding.** Compensatory damages shall not be awarded by the Panel in any Binding Arbitration Proceeding decision. These Bylaws shall neither restrict nor enhance any Member's right to seek judicial redress of any alleged compensatory damages with respect to any matters relating to these Bylaws.

10.19 **Costs of Binding Arbitration Proceeding.** Each party shall bear its own costs, including attorneys fees, associated with the Dispute Resolution Proceeding and preparation thereof. All other expenses of the Binding Arbitration Proceeding (e.g. arbitrators' fees, court reporters fees) shall be borne by the losing Party or Parties (as determined by the Panel), unless the Parties agree to an alternate method of allocating costs.

10.20 **Regulatory Approval.** Except as otherwise provided in Section 10.11.3, to the extent the decision requires or involves regulatory action, all Parties and Indispensable Intervenors to the Binding Arbitration Proceeding shall submit and fully support the Binding Arbitration Proceeding decision before the appropriate Regulatory Authority. However, Members shall be relieved of their obligations to comply with the Binding Arbitration Proceeding decision and the compliance schedule in the event that the legally required approval of a Regulatory Authority is denied, or in the event that the Regulatory Authority denies the requested ratemaking treatment such that the Member is prevented from recovering prudently incurred costs required in implementing the Binding Arbitration Proceeding decision. Members that fail to obtain regulatory or other agency approval of the Dispute Resolution Proceeding decision (except as provided in Section 10.14) are subject to the expulsion provision of Section 8.4.

10.15.3 Requirements of Transmission Provider Regarding FERC Application. With respect to the FERC application filed in accordance with Section 10.15.1, the Transmission Provider shall file an appropriate response with FERC fully supporting the issues, terms conditions, provisions and matters identified in Section 10.15.1(ii) and (iii). The Transmission Provider shall set forth its position regarding any issue, term, condition, provision, matter or decision identified in Section 10.15.1(iv) including the authority of FERC to issue an order pursuant to Section 210 and/or 211 (unless such issue was determined in Section 10.15.1(ii) or (iii)), may fully support or contest any issue, term, condition, provision, matter or decision identified in Section 10.15.1(v), and may fully support or contest the exclusion or inclusion of any such issues, terms, conditions, provisions, matters or decisions in such FERC order.

10.15.4 Appellate Role of FERC. In its appellate role, FERC should give substantial deference to decisions of the Panel in a Binding Arbitration Proceeding. An appeal to FERC of any Panel decision which contains both FERC-jurisdictional and non-FERC-jurisdictional matters shall not impute FERC jurisdiction over such non-FERC-jurisdictional matters; provided however, FERC should consider any relevant non-FERC-jurisdictional matter involved in such Binding Arbitration Proceeding in rendering its decision regarding such FERC-jurisdictional matters.

10.15.5 FERC Determination Matters Resolved by FERC on De Novo Basis. FERC shall resolve FERC Determination Matters on a de novo basis.

10.16 **File Rate Schedule with FERC and/or Execute Contract.** Subject to the filing, prosecution and completion of any appeal to a court of competent jurisdiction of a final order of FERC with respect to the application filed pursuant to Sections 10.15.1 and 10.15.2, promptly (but no more than 45 days) following the issuance of a final, nonappealable FERC order requiring service under Section 210 and/or 211, the Transmission Provider shall provide an executable contract in accordance with such FERC order. Unless otherwise agreed to by the Transmission Provider and the Transmission Requester, the Transmission Requester must, within 45 days of its receipt, execute the contract and deliver it to the Transmission Provider. Failing the receipt by the Transmission Provider as provided in the preceding sentence, the Transmission Provider shall not be required to provide the service ordered by FERC, and the Transmission Provider's request pursuant to Section 5 and the applicable Appendix A shall be deemed null and void.

10.16.1 Type 1 Transaction. With respect to a Type 1 transaction, upon receipt of the contract executed by the Transmission Requester in accordance with Section 10.16, the Transmission Provider shall promptly (but no

10.15 **FERC Review of Arbitration Decision and Resolution of FERC Determination Matters.** If (i) any Party serves a notice of appeal regarding a decision, or any portion thereof with respect to Regular Arbitration, of a Binding Arbitration Proceeding in accordance with Section 10.14, or (ii) there are FERC Determination Matters in accordance with Section 10.5, 10.8.7 or 10.8.8:

10.15.1 Transmission Requester File Application with FERC: Contents of Application. The Transmission Requester shall file an application with FERC for an order under Section 210 and/or Section 211, as the case may be. The application shall include, but is not limited to, the following information:

(i) A transcript of the Binding Arbitration Proceeding;

(ii) All issues, terms, conditions, provisions or matters which the Parties agreed or stipulated to pursuant to Section 10.8.4;

(iii) All issues, terms, conditions, provisions or matters which were determined in the Binding Arbitration Proceeding which are not being appealed by any Party;

(iv) All issues, terms, conditions, provisions or matters which are FERC Determination Matters; and

(v) All issues, terms, conditions, provisions, matters or decisions appealed from a Binding Arbitration Proceeding.

10.15.2 Requirements of the Transmission Requester Regarding FERC Application. With respect to the FERC application filed in accordance with Section 10.15.1, the Transmission Requester shall request FERC to issue an order pursuant to Section 210 and/or Section 211, as the case may be, including the issues, terms, conditions, provisions and matters identified in Section 10.15.1(ii) and (iii). The Transmission Requester shall set forth its position regarding any issue, term, condition, provision, matter or decision identified in Section 10.15.1(iv), may fully support or contest any issue, term, condition, provision, matter or decision identified in Section 10.15.1(v), and may fully support or contest the exclusion or inclusion of any such issues, terms, conditions, provisions, matters or decisions in such FERC order.

7.4.2 For any federal power marketing agency that is a Member, FERC shall review any binding arbitration decision concerning rates, or which imposes an obligation to upgrade or install additional transmission facilities or provide an interconnection, for material inconsistency with the provisions of other applicable laws.

the Manager within 14 days following the date of the Award. If such notice of appeal is timely provided:

(a) Within 10 days of the date of the first notice of appeal that is provided, the disputing Member requesting transmission service shall file an application with the FERC pursuant to Section 211 of the FPA. Such application shall state that the service requested has been the subject of an arbitration pursuant to this Governing Agreement.

(b) Within 14 days of the date of such first notice of appeal, the disputing Member providing such notice shall file its statement of position regarding the appeal with the FERC together with the complete evidentiary record of the appeal and a copy of the Award.

(c) Within 30 days of the date of such first notice of appeal, any other disputing Member that was a party to the arbitration may file its statement of position regarding the appeal with the FERC.

(d) Copies of all materials filed with the FERC by a disputing Member during the course of an appeal shall be delivered to all other disputing Members and the Manager.

(e) Implementation of the Award shall be deemed stayed for 90 days pending an appeal unless and until, at the request of a disputing Member, the FERC issues an order shortening or extending such stay.

(f) A summary of each appeal shall be published by the Manager in the Association's newsletter or electronic bulletin board.

(g) The Members intend that FERC orders resulting from appeals shall be subject to judicial review pursuant to Section 313 of the FPA.

12.7 Canadian or Mexican Appeal. Notwithstanding Subsection 12.5, a disputing Member may apply to the appropriate Canadian or Mexican governmental or regulatory authority to hear an appeal of any Award associated with transmission access or services utilizing facilities located in Canada or Mexico. The standards and procedures for appeals shall be reasonably comparable to those set out in Subsections 12.5 and 12.6.

10.13 Execute Contract; File Rate Schedule with FERC. With respect to providing interconnection or transmission service (including matters relating to Incremental Additions) and subject to the filing, prosecution and completion of any appeal permitted in accordance with Section 10.14.

(i) As soon as practicable (but no more time than the number of days remaining in the time period to provide such contract as provided in the applicable Appendix A) following a decision in a Binding Arbitration Proceeding pursuant to Section 10.11, the Transmission Provider shall provide an executable contract to the Transmission Requester setting forth or implementing the terms of the decision and the list of terms and conditions stipulated pursuant to Section 10.8.4. Unless otherwise agreed to by the Transmission Provider and the Transmission Requester, the Transmission Requester must, within 30 days of its receipt, execute the contract and deliver it to the Transmission Provider. The Transmission Provider shall execute such contract within 10 days of its receipt from the Transmission Requester. Failing the receipt by the Transmission Provider, the Transmission Provider shall not be required to provide the service described in such contract and the Transmission Provider's obligation to provide such service shall be discharged.

(ii) With respect to a Type 1 Transaction, except as otherwise agreed to by the Transmission Requester and the Transmission Provider or as otherwise provided in the contract, the Transmission Provider shall file such contract, including any supporting documentation, with FERC as a rate schedule or rate schedule amendment, as the case may be. The Transmission Provider and the Transmission Requester shall both fully support such filing. The contract executed by the Transmission Provider and the Transmission Requester shall, unless otherwise agreed to by such entities, have the same force and effect, and create the same rights and obligations, as an order of FERC issued under Sections 210 and/or 211 of the FPA.

10.14 Appeal to FERC. Any Party may appeal to FERC as an appellate body any decision, or any portion thereof with respect to Regular Arbitration, rendered pursuant to Section 10.11, only upon the grounds that the decision is contrary to, or beyond the scope of, these Bylaws or is inconsistent with any then applicable FERC order, rule or precedential determination, or is unlawful, unjust, unreasonable, unduly discriminatory or preferential. Any Party appealing a Panel's decision shall serve a notice of appeal on all entities listed on the Service List within 21 days of the date of such decision. The notice of appeal shall include the basis of the appeal.

7.4 Appeals

7.4.1 On the basis of a protest by a Commission or affected non-member, or on its own motion, FERC may investigate any arbitration decision made under these Bylaws and, after giving substantial deference to such decision, may set it aside if the decision is determined to be materially inconsistent with the basis upon which these Bylaws were approved by FERC or applicable federal law or regulation. A disputing Member may file a protest or complaint with FERC regarding the arbitration process or decision only (i) if the arbitration process does not result in a decision within a reasonable period of time, or (ii) on the grounds specified in Sections 10 and 11 of Title 9, United States Code, for judicial vacation or modification of an arbitration award.

12.5 FERC Appeal. A disputing Member may apply to the FERC to hear an appeal of any Award only upon the grounds that the Award is contrary to or beyond the scope of this Governing Agreement or is unjust, unreasonable, unduly discriminatory or preferential or otherwise inconsistent with the FPA or FERC's standards or policies. Any appeal to the FERC shall be based solely upon the record assembled by the Arbitrator. The Parties intend that deference shall be afforded only to the factual findings of the Arbitrator. No Member, whether or not a party to the arbitration giving rise to the Appeal, shall seek to expand the factual record before the FERC beyond that assembled by the Arbitrator.

12.6 Procedures for Appeals. If any disputing Member desires to appeal an Award, it shall provide written notice to that effect to all other disputing Members, the Arbitrator and

10.11.1.2 With respect to Regular Arbitration, within thirty (30) days after the conclusion of the Binding Arbitration Proceeding hearing the Panel shall, by a majority vote, adopt a decision.

10.11.2 Panel Unable to Adopt Proposal. With respect to Baseball Arbitration, to the extent that the Panel finds it cannot adopt the Proposal of one or more of the Parties because the Proposal(s) does not conform with applicable law and/or these Bylaws, the Panel may elect either to: (i) issue a final decision adopting a Proposal of a Party which does conform to applicable law and these Bylaws; or (ii) notify the Parties of its ruling as to the law or Bylaw provisions at issue and allow them to submit revised Proposals conforming to such ruling.

10.11.3 Written Decision Binding on Parties. The Panel's decision shall be in writing. Where subsequent Regulatory Authority approval is necessary to implement the Proposal or any issue determined by a Panel's decision, the Panel shall provide, if requested by any Party, written findings of fact (for Regular Arbitration) or a written basis of the decision (for Baseball Arbitration) with respect to the Proposal or such issue. Subject to the filing, prosecution and completion of any appeal permitted in accordance with Section 10.14, the decision of the Panel shall be binding upon all Parties. A decision in one Binding Arbitration Proceeding shall not be a precedent for a decision in any other Binding Arbitration Proceeding.

10.12 Compliance Schedule. Subject to the filing, prosecution and completion of any appeal permitted in Section 10.14, a schedule for compliance shall be set forth in the Panel's decision, or, in the alternative, shall be determined as provided in Sections 10.12.1 through 10.12.3. Subject to the filing, prosecution and completion of any appeal permitted in Section 10.14, the Parties shall take whatever action is required to comply with the Panel's decision and the compliance schedule.

10.12.1 Mutually Agree to Schedule. The Parties shall meet and confer in good faith to agree upon a compliance schedule within seven calendar days of the Panel's decision (days one through seven).

10.12.2 Submit Proposed Schedule to Panel. If the Parties fail to agree within this initial seven-day period (days one through seven), each Party shall then submit a proposed compliance schedule to the Panel within the next seven calendar days (days eight through fourteen).

10.12.3 Panel Selects Schedule. The Panel shall select one of the proposed compliance schedules within seven calendar days thereafter (days fifteen through twenty-one).

12.4 Compliance and Costs. Immediately upon the decision by the Arbitrator, except as provided for in Subsection 12.5, the disputing Members shall take whatever action is required to comply with the selected Award to the extent the selected Award does not require regulatory action and shall pursue no avenue of appeal. To the extent the Award requires state or provincial regulatory action, FERC review of an Award involving a Power Marketing Agency or a FERC filing by a Transmission Provider subject to FPA Sections 205 or 206, the affected Member shall submit and support that portion of the Award with the appropriate regulatory authority. Any and all costs associated with the arbitration shall be borne by the Member or Members whose proposed Award was not selected, unless the disputing Members agree to an alternate method of allocating costs. Except for it not being precedential in other arbitrations, an Award that is not appealed shall be deemed to have the same force and effect as an order entered by the FERC pursuant to Section 211 of the FPA and a failure to comply with such an Award shall be deemed equivalent to a failure to comply with an order entered by the FERC and subject to enforcement pursuant to Section 314 of the FPA or through a suit for specific performance in a court of competent jurisdiction.

10.10.4 Insufficient Standard for Decision. Where the Panel determines that the standards provided in this Section 10.10 are insufficient in order for the Panel to render a decision regarding non-FERC-jurisdictional issues, the panel shall request the Planning Committee to develop a sufficient standard upon which to render a decision, which standard must be approved by the Board of Directors. If such a standard is not developed within a reasonable period of time, the Panel may dismiss such non-FERC jurisdictional issues.

10.10.5 Rebuttable Presumption Electric System Operated Consistent with Prudent Utility Practice. The Transmission Provider shall have a rebuttable presumption that the then current operation of its system is consistent with Prudent Utility Practice; however no such rebuttable presumption shall apply where it is contended that the Transmission Provider's system operational procedures or practices are not Consistently Applied.

10.10.6 Proposal Consistent with Prudent Utility Practice. Each Party's proposal must be consistent with Prudent Utility Practice to warrant consideration by the arbitration panel.

10.10.7 Standards Regarding Requests for Transmission Requests. With respect to matters related to a request for interconnection and/or transmission service in accordance with Section 5 and the applicable Appendix A of these Bylaws, the Panel's decision shall be rendered to produce a result which is within the range of results which could apply if FERC were requested at that time to issue an order to provide service pursuant to Section 210 and/or 211 of the FPA, as the case may be, on the same matters, and in accordance with other applicable provisions of the FPA, applicable FERC regulations, policies and precedents, and these Bylaws, in each case as then in effect; provided however, in the event of a conflict between these Bylaws and the provisions of the FPA or applicable FERC regulations, policies or precedents, these Bylaws shall prevail to the extent permitted by law.

10.11 Panel's Decision.

10.11.1 Acceptance of One Proposal; Preparation of Arbitration Time Frame.

10.11.1.1 With respect to Baseball Arbitration, within twenty (20) days after the conclusion of the Binding Arbitration Proceeding hearing the Panel shall, by a majority vote, accept one of the submitted Proposals, without modification (except as provided in Section 10.11.3).

10.9 Binding Arbitration Proceeding Hearing

10.9.1 Procedures and Evidence at Hearing. The Panel shall provide for hearings to receive evidence submitted by the Parties in accordance with procedures established by the Panel. The hearing procedures adopted by the Panel shall afford each Party the right to present to the Panel any relevant evidence and to rebut any evidence submitted by any other Party.

At any time during the course of the hearing, the Panel may request from the Parties additional evidence to be presented at the hearing related to issues identified in the Joint Statement or the Panel's Statement of Issues, as the case may be.

10.9.2 Party Failure to Appear. The failure of any Party to appear at the hearings or to present evidence or a Proposal shall not prevent the Panel from proceeding with the hearing and rendering a decision.

10.9.3 Solicit Proposal. If "Baseball" Arbitration is utilized, the Panel shall solicit a proposal from each Party. Each proposal shall include a proposed remedy for each issue that is the subject of the Binding Arbitration Proceeding (a "Proposal"); provided that with respect to any Indispensable Intervenor, its Proposal shall be limited to the issues affecting its interests.

10.10 Factors and Standards Regarding Binding Arbitration Proceeding Decision.

10.10.1 Evidence Considered by the Panel. To adopt a decision, the Panel shall consider evidence presented during the hearing for the Binding Arbitration Proceeding regarding issues included in the Joint Statement or the Panel's Statement of Issues, as the case may be.

10.10.2 Interpretation of Bylaws. In arriving at a decision, the Panel must necessarily interpret and construe these Bylaws; however, nothing contained in this Section 10 shall be deemed to permit the Panel to waive or change any of the express provisions of these Bylaws.

10.10.3 Decision Consistent with Applicable Law and Bylaws. The Panel's decision shall be consistent with the provisions and intent of these Bylaws, Prudent Utility Practice and applicable state or federal law (including the FPA and FERC regulations, policies and precedents). In the event of a conflict between these Bylaws and applicable state or federal law, these Bylaws shall prevail to the extent permitted by law.

10.8.5 Establish Discovery and Hearing Schedule. The Panel shall authorize necessary discovery regarding the Panel's Statement of Issues or the Joint Statement and establish the Binding Arbitration Proceeding hearing schedule. The Panel may authorize discovery of information related to issues included in the Joint Statement or in the Panel's Statement of Issues, as the case may be.

10.8.6 Schedule Procedural Matters. The Panel shall schedule summary judgment motions, discovery, and such other procedural matters as the Panel deems appropriate to a fair and expeditious resolution of the dispute.

10.8.7 Determine if Matters Subject to Dispute Are FERC Determination Matters; Refer to FERC. Upon the request of any Party, the Panel shall determine during prehearing proceedings, when practicable, whether (i) all matters in dispute are FERC Determination Matters or (ii) certain matters in dispute are FERC Determination Matters and all other matters in dispute are dependent upon the resolution of the FERC Determination Matters. If the Panel determines either such circumstance to be the case, then the FERC Determination Matters and related disputed matters, if any, shall be submitted to FERC in accordance with Section 10.15. If during the prehearing proceedings, the Panel is unable to determine with certainty whether any matter in dispute is a FERC Determination Matter, the Panel may defer such determination until the conclusion of the evidentiary phase of the Binding Arbitration Proceeding hearing.

10.8.8 Determine Certain Matters Subject to Dispute Are FERC Determination Matters. If the Panel determines that certain matters in dispute are FERC Determination Matters and other matters in dispute are not dependent upon the resolution of the FERC Determination Matters, then disputed matters which are not dependent upon the resolution of FERC Determination Matters shall first be determined pursuant to a Binding Arbitration Proceeding. Following such determination, the Binding Arbitration Proceeding decision regarding matters not dependent upon the resolution of the FERC Determination Matters and the FERC Determination Matters shall be submitted to FERC in accordance with Section 10.15.

10.8.9 Panel Decision Not Subject to Interlocutory Appeal. No determination by the Panel of any issue relating to FERC Determination Matters, as provided in Section 10.8.7 or 10.8.8, shall be subject to an interlocutory appeal to FERC or any court.

If said agency or ex officio member declines to agree to be bound by the decision, or lacks the authority to be so bound, then notwithstanding Sections 6.1, 10.14 or 10.15, the Panel's decision shall not be binding upon said agency or ex officio member and Panel's decision may not be appealed by said agency or ex officio member. The agency or ex officio member shall, however, be entitled to file an advisory Proposal. The Panel must consider such an advisory Proposal; however, the acceptance or rejection of such a Proposal is within the sole determination of the Panel.

For purposes of a Binding Arbitration Proceeding, "Party" or "Parties" shall mean the Initiating Party(ies), the Respondent(s), and the Indispensable Intervenor(s).

10.8.3 Determine Type of Arbitration. Baseball Arbitration shall be the method of binding arbitration under these Bylaws unless the Panel determines that Baseball Arbitration is unworkable, ineffective or inappropriate because of the existence of special circumstances. Such special circumstances may include: i) the presence of multiple Parties with multiple issues so that it is highly unlikely that a single Proposal will adequately and fairly address all issues and/or interests; or ii) the presence of other factors that render Baseball Arbitration ineffective, unworkable or inappropriate. If the Panel determines that Baseball Arbitration is ineffective, unworkable or inappropriate, then Regular Arbitration shall be utilized unless the Parties mutually agree to another method of dispute resolution. The Panel shall make a decision on the form of binding arbitration at the Prehearing Conference.

For purposes of a Binding Arbitration Proceeding:

"Baseball Arbitration" refers to a binding arbitration method where the Panel renders its decision by selecting a Proposal, in its entirety, of one of the Parties.

"Regular Arbitration" refers to a binding arbitration method where no Proposal is submitted by the Parties, but rather the Panel, in its sole determination, fashions the remedy or resolution set forth in its decision.

10.8.4 Determine Statement of Issues and Direct Preparation of Joint Stipulation. The Panel shall direct the Parties to submit a joint stipulation of the issues agreed upon by the Parties. The Panel shall also direct the Parties to prepare a joint statement of disputed issues (the "Joint Statement"). Failing the preparation of a Joint Statement, the Panel shall determine which disputed issues submitted by Parties best reflect the nature of the dispute outlined by the Parties and should be the subject of the Binding Arbitration Proceeding (the "Panel's Statement of Issues").

resignation. The same procedure shall be used to select a Panel member if the person whom a Party selects for the Panel is unable to fulfill his or her role as arbitrator due to other commitments or unavailability.

10.8 **Prehearing Conference.** Within 15 days of the selection of the Panel, the Panel shall conduct a noticed prehearing conference. The Panel shall conduct and complete the Binding Arbitration Proceeding as quickly and efficiently as possible. At or as soon as practicable following the prehearing conference, the Panel shall undertake the following activities.

10.8.1 Procedures and Evidence at Prehearing. The Panel may receive evidence submitted by the Parties during prehearing proceedings in accordance with procedures established by the Panel. The prehearing procedures adopted by the Panel shall afford each Party the right to present to the Panel any relevant evidence and to rebut any evidence submitted by any other Party.

At any time during the course of the prehearing proceedings, the Panel may request from the Parties additional evidence to be presented at the prehearing proceeding related to issues identified in the Joint Statement or the Panel's Statement of Issues, as the case may be.

10.8.2 Rule on Motions to Intervene. The Panel shall rule on any Motions to Intervene, which ruling shall include a finding regarding the indispensability of the moving intervenor. An intervenor is indispensable ("Indispensable Intervenor") if: (i) the intervenor demonstrates a direct and immediate interest relating to the property or transaction that is the subject of the dispute; (ii) the intervenor's ability to protect that interest may as a practical matter be impaired or impeded by the disposition of the Binding Arbitration Proceeding; and (iii) the intervenor's interest is not adequately represented by the Initiating Party or Respondent. Only Indispensable Intervenors shall be permitted to become a Party to a Binding Arbitration Proceeding.

In the event that a state or federal agency (or subdivision thereof), including an ex officio member, qualifies as an Indispensable Intervenor, said agency or ex officio member may fully participate in the Binding Arbitration Proceeding as a Party. Said agency or ex officio member, however, shall not be entitled to submit a Proposal unless said agency or ex officio member has expressly agreed in writing to be bound by the decision, and has the authority to be so bound.

members should be knowledgeable in matters involving the electric utility industry in general and the matters involved in the dispute, to the extent practicable. Panel members must disclose to the Parties and intervenors any potential interest they may have in the dispute and shall be obliged to disqualify themselves from the Dispute Resolution Proceeding in accordance with the American Bar Association Code of Judicial Conduct.

The two arbitrators selected by the Initiating Party and the Respondent pursuant to Sections 10.6.3 and 10.6.5 or 10.7.3 shall, within 20 days of being notified by one of the Parties of their selection for such Binding Arbitration Proceeding, choose and appoint a third arbitrator from any list of arbitrators or any other agreed upon individual. The three arbitrators shall constitute the Panel for the dispute.

Notwithstanding the provisions of this Section 10.7.2, the Initiating Party and the Respondent may mutually agree to an alternative method for the selection of arbitrators provided the number of arbitrators selected for the Panel does not exceed three.

10.7.3 Impasse in Selection of Arbitrator (Multiple Respondents). In the case of multiple Respondents, if after meeting and conferring in good faith, the multiple Respondents are unable to jointly select an arbitrator within 20 days of receipt of the Initiating Party's Notice, the Respondents shall so notify the Board. The Board, or a Board-appointed Binding Arbitration Procedure subcommittee, shall appoint an arbitrator from the list of arbitrators developed by the membership category of which the Initiating Party is a member. The two selected arbitrators shall then proceed to select a third arbitrator pursuant to Section 10.7.2. In the event the Board or the Board-appointed subcommittee fails to appoint the second arbitrator within 10 days of the Respondent's notification to the Board, then the Initiating Party shall select an arbitrator from the list of arbitrators developed by the membership category of which the Initiating Party is a member. The two selected arbitrators shall then proceed to select a third arbitrator pursuant to Section 10.7.2.

10.7.4 Replacement of Arbitrators. If a Panel member is removed for good cause by a vote of the Board or resigns, the process by which the absent Panel member was selected shall be used to select a successor arbitrator, with the time period for selection commencing on the date of the arbitrator's removal or

10.6.9 Service of Process. For purposes of Sections 10.6 through Section 10.12, "service" of a notice, filing, or document shall be either by (i) personal delivery to the party's representative or process agent (see Section 10.6.7) or (ii) certified mail, return receipt requested, to such representative or process agent.

10.7 Arbitration Panel Selection

10.7.1 List of Arbitrators. The Board shall maintain a list of ten arbitrators for each membership category.

10.7.1.1 The lists of arbitrators shall be developed and updated, from time to time, at a meeting called by the Board for this purpose. Each membership category shall have the right, by majority vote of the Members of such membership category in attendance at the meeting, to nominate an appropriate number of potential arbitrators so that its list will contain the names of ten arbitrators. Each membership category on the Board shall also have the right, by majority vote of the Members in such membership category in attendance at the meeting, to remove the name of any arbitrator submitted by that membership category and subsequently approved by the Board pursuant to Section 10.7.1.2.

10.7.1.2 By majority vote of the Directors, the Board shall determine whether to add any arbitrator's name nominated by any membership category to be added to its list of arbitrators. By majority vote of the Directors, the Board may delete any arbitrator's name from the list of arbitrators for any membership category.

10.7.1.3 If any membership category is unable to nominate a sufficient number of arbitrators which are subsequently approved by the Board so as to maintain a list of ten arbitrators, the Board of Directors may select, by majority vote of the Directors, sufficient names of arbitrators so as to maintain ten arbitrators on each membership category list.

10.7.1.4 The same arbitrator may be placed on more than one list of arbitrators.

10.7.2 Selection of Arbitrators for Panel. No person shall be eligible for appointment to the Panel who is an officer, member of the governing body, employee or consultant of any of the parties to the dispute or is otherwise interested in the matter to be submitted to the Binding Arbitration Proceeding. Panel decision involving a federal power marketing agency, or a FERC filing by a Transmitting Member subject to the FPA, the affected Member shall submit and fully support that portion of the decision in the appropriate regulatory authority. Disputing Members shall bear their own costs associated with the arbitration. All other verifiable costs and expenses associated with the arbitration, including required travel and other expenses of the Arbitrator and witness costs and costs of proof incurred at the direct request of the Arbitrator, shall be borne equally by the disputing Members.

receipt of the Response, serve a Notice of Motion to Intervene. The Notice of Motion to Intervene shall be in a form approved by the Board. No Member or non-Member may intervene in a Binding Arbitration Proceeding without first serving a timely Notice of Motion to Intervene on the Initiating Party, the Respondent, and the Board. The proposed intervenor shall also provide a written copy of its Notice of Motion to Intervene to any entity on the Mailing List requesting a copy thereof within five (5) business days of such request.

10.6.7 Preparation of Service List. Upon expiration of the 5-day period for Notice of Intervention provided in Section 10.6.6, the Initiating Party shall prepare a list (the "Service List") comprised of the names and addresses of: the Initiating Party, the Respondent, the Board, and all entities who have served a timely Notice of Motion to Intervene. The Initiating Party shall serve a written copy of the Service List on each entity therein contained within five (5) business days following the expiration date for submission of a Notice of Motion to Intervene.

10.6.8 Motion to Intervene. Each entity filing a Notice of Motion to Intervene shall serve a copy of its Motion to Intervene on all other entities on the Service List within 5 business days of receipt of the Service List. The Motion shall be in a form approved by the Board. The Motion shall, at a minimum, provide:

(i) A full statement explaining the intervenor's interest in the Binding Arbitration Proceeding, how the intervenor may be affected by the Binding Arbitration Proceeding, and why the proposed intervenor is an indispensable party to the Binding Arbitration Proceeding;

(ii) The intervenor's position on each issue set forth in the Initiating Party's Notice and the Response;

(iii) A statement of any additional issues to be submitted in the Binding Arbitration Proceeding and the intervenor's position on each such issue; provided however, no intervenor shall be permitted to include additional issues which are beyond the scope of the dispute or are inconsistent with these Bylaws;

(iv) The intervenor's recommended remedy or relief, if any, with respect to issues described in (ii) and (iii) above; and,

(v) In the case of an intervening non-Member, a signed statement that such non-Member agrees to be subject to and bound by the decision in the Binding Arbitration Proceeding, and shall further agree to support such decision in any subsequent regulatory proceeding, subject to the right of appeal as provided in Section 10.14.

of the governing body, employee, consultant or shareholder of any of the disputing Members, or of a business entity related to or affiliated with any of the disputing Members, or is otherwise interested in the matter to be arbitrated, and any individual designated as a potential Arbitrator who is ineligible to serve pursuant to these guidelines shall disclose the circumstances affecting his or her impartiality and shall disqualify himself or herself from serving as Arbitrator.

7.3.4 The Arbitrator shall set a timetable for the arbitration, including setting the date, time and place of each hearing. The Arbitrator shall accept relevant and material evidence and hear testimony presented by the disputing Members and may request additional information and testimony. Such additional information shall be furnished by the Member or Members and by other entities having such information. Other affected entities may request in writing that the Arbitrator consider additional information and the Arbitrator shall decide whether to consider such additional information.

7.3.5 Not later than thirty (30) days after the date of closing of hearings, each disputing Member shall submit its proposed remedy to the Arbitrator. No later than thirty (30) days after receipt of the disputing Member's proposed remedy, the Arbitrator shall determine which proposal best meets the terms and intent of these Bylaws and conforms with the FPA and FERC's standards and policies, consistent with Prudent Utility Practice, and shall state his or her decision in writing. The disputing Members agree to be bound by the Arbitrator's decision.

7.3.6 Immediately upon their receipt of the written decision of the Arbitrator, the disputing Members shall take whatever action is required to comply with the decision to the extent the decision does not require regulatory action. To the extent the decision requires state or provincial regulatory action, FERC review of a changes in governance described in attached Exhibit A, WSCC standards, procedures and guidelines adopted between July 1, 1993 and such time shall be arbitratable with the same degree of deference as would be given them in a Section 211 proceeding by the FERC. The Arbitrator may elect to resolve the disputed matter solely on the basis of written submittals.

12.2.4 The Arbitrator shall take evidence submitted by the disputing Members in accordance with procedures established by the Arbitrator and may request additional information including the opinion of recognized technical bodies. Disputing Members shall be afforded a reasonable opportunity to rebut any such additional information. Other affected parties may request in writing that the Arbitrator consider additional information and the Arbitrator may consider such additional information, subject to a right of the disputing Members to have a reasonable opportunity to rebut such additional information.

12.3 Award. The Arbitrator shall consider the matter as a request for an order requiring the provision of transmission service pursuant to Section 211 of the FPA. Within 115 days of his or her selection, the Arbitrator shall select, by written notice to the disputing Members, the proposed Award of a disputing Member which best meets the terms and intent of this Governing Agreement, the FPA and FERC's standards and policies; provided, however, if the Arbitrator concludes that no proposed Award is consistent with law or applicable FERC policy, the Arbitrator shall specify how each proposed Award is deficient and request that the disputing Members submit new proposed Awards that cure the deficiency perceived by the Arbitrator. A written decision explaining the basis for the Award shall be provided by the Arbitrator with the written notice to parties. Both notice and decision shall be published in the Association's newsletter or electronic bulletin board. No Award shall be deemed to be precedent binding on an Arbitrator in any other arbitration related to a different dispute.

issues to be resolved in the Binding Arbitration Proceeding; (iii) a list of related matters which the Initiating Party is willing to stipulate to; (iv) the Initiating Party's position on each issue; and (v) the requested remedy or relief. The Notice shall also include a list of the related matters which the Initiating Party is willing to stipulate to.

Such Notice shall also call for the appointment of a panel of arbitrators (the "Panel"). The Initiating Party shall indicate its choice of an arbitrator in the Notice. The arbitrator must be selected from the list of arbitrators developed by the membership category of which the Respondent is a member. If the Initiating Party includes more than one Member, the Notice and the selection of the arbitrator shall be prepared jointly.

10.6.4 Form of Response. Within thirty (30) days from receipt of such Notice, each Respondent shall serve all entities identified on the Mailing List with a written response in a form approved by the Board (the "Response"). The Response shall, at a minimum, describe: (i) the nature of the dispute; (ii) a statement of issues to be resolved in the Binding Arbitration Proceeding; (iii) a list of related matters which the Respondent is willing to stipulate to; (iv) the Respondent's position on each issue; and (v) the requested remedy or relief, if any.

The Respondent shall also provide a written copy of its Response to any entity on the Mailing List requesting a copy thereof within five (5) business days receipt of such request.

10.6.5 Name Second Arbitrator. In addition to the above information, the Respondent shall provide in its Response the name of a second arbitrator. The arbitrator must be selected from the list of arbitrators developed by the membership category of which the Initiating Party is a member. If there are multiple Respondents, such Respondents shall meet and confer in good faith to select a second arbitrator. If the multiple Respondents are unable to do so within twenty (20) days of receipt of the Initiating Party's Notice, then the Respondents shall notify the Board, and the selection of the second arbitrator shall be in accordance with the provisions of Section 10.7.3 below.

10.6.6 Notice of Motion to Intervene. A Member or non-Member having preexisting rights which could be affected by such dispute and desiring to intervene in the Binding Arbitration Proceeding shall, within 5 business days of

available to Members, including arbitration under Section 7.3 hereof, and the provisions of this Section 7.2 shall be the exclusive means of dispute resolution available to Members until such means are exhausted according to their terms.

7.2.5 The President shall report the outcome of the mediation process to all Members.

7.3 Arbitration

7.3.1 Within thirty (30) days of the disputing Members' mutual agreement to elect arbitration, each disputing Member shall submit a statement in writing to the other disputing Member, which statement shall set forth in adequate detail the nature of the dispute, the issues to be arbitrated, and the remedy sought through such arbitration proceedings. These statements shall constitute the sole submittal of statements initiating arbitration.

7.3.2 Within ten (10) working days following the submission of their statements, authorized representatives of the disputing Members shall meet for the purpose of selecting an Arbitrator.

7.3.3 Arbitration shall be conducted by an Arbitrator familiar with and knowledgeable about the policies and criteria of WSCC, transmission systems, and federal statutory and regulatory requirements. If the disputing Members cannot agree upon an Arbitrator, each disputing Member shall take turns striking names from a list of ten (10) qualified individuals supplied by the President from the list maintained by the Board pursuant to Section 14.8 hereof, with a disputing Member chosen by lot first striking a name. The last-remaining name not stricken shall be designated as the Arbitrator. If that individual is unable, unwilling or ineligible to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected who is eligible and willing to serve. No person shall be eligible for appointment as an Arbitrator who is an officer, member from the list maintained by the Board pursuant to Subsection 6.9 with a disputing Member chosen by lot first striking a name. The last-remaining name not stricken shall be designated as the Arbitrator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected who is able and willing to serve. Absent the express written consent of all disputing Members as to any particular individual, no person shall be eligible for selection as an Arbitrator who is a past or present officer, member of the governing body, employee of or consultant to any of the disputing Members, or of an entity related to or affiliated with any of the disputing Members or is otherwise interested in the matter to be arbitrated. Any individual designated as an Arbitrator shall make known to the disputing Members any such disqualifying relationship and a new Arbitrator shall be designated in accordance with the provisions of this subparagraph.

12.2.3 The Arbitrator shall determine discovery procedures, intervention rights, how evidence shall be taken, what written submittals may be made, and other such procedural matters, taking into account the complexity of the issues involved, the extent to which factual matters are disputed and the extent to which the credibility of witnesses is relevant to a resolution. The Arbitrator shall consider all issues underlying a dispute including, if relevant, the reasonableness of a disputing Transmission Provider's reliability criteria, standards, guidelines and operating criteria; provided, that individual Members' reliability criteria, standards, guidelines and operating procedures which were in effect and in writing as of July 1, 1993 (but not the applicability, application or interpretation of such criteria, standards, operating procedures and guidelines in regard to a particular request) shall be afforded a rebuttable presumption of reasonableness and consistency with Prudent Utility Practice by the Arbitrator. Until such time as the WSCC has achieved the

matters in dispute are dependent upon the resolution of the FERC Determination Matters, then the FERC Determination Matters, and related disputed matters, if applicable, shall be submitted to FERC in accordance with Section 10.15.

10.5.2 Agreement Certain Matters Subject to Dispute Are FERC Determination Matters. If the disputing Members agree that certain matters in dispute are FERC Determination Matters and other matters in dispute are not dependent upon the resolution of the FERC Determination Matters, then the disputing Members shall first resolve, by mutual agreement or in accordance with Section 10.6, all other disputed matters which are not dependent upon the resolution of FERC Determination Matters. The disputing Members shall then submit such matters and the FERC Determination Matters to FERC in accordance with Section 10.15.

10.5.3 No Agreement Matters Subject to Dispute Are FERC Determination Matters. If the disputing Members cannot agree that certain matters in dispute are FERC Determination Matters, the disputing Members shall submit such matters to a Binding Arbitration Proceeding in accordance with Sections 10.6 through 10.12.

10.6 Binding Arbitration Procedure. Except as specifically provided in Sections 10.2.2 and 10.2.3, the provisions of Section 10.6 through 10.12 shall be applicable to all disputes arising out of any matter relating to these Bylaws.

10.6.1 Mailing List. The Board or its designee shall maintain a current mailing list (the "Mailing List") containing the names of all Members and, to the extent they make themselves known, the names of all non-Members whose interests may be affected by WATSCO disputes (as determined by the Board or its designee), including the names and addresses of their representatives or process agents for purposes of receiving service of process (see Section 10.6.7 below).

10.6.2 Initiating Member Notice. Any disputing Member may call for submission to a Binding Arbitration Proceeding of matters in dispute, the subject of which are not listed in Sections 10.2.2 or 10.2.3. The disputing Member calling for a Binding Arbitration Proceeding (the "Initiating Party") shall serve a written notice (the "Notice") on: (i) the other Member(s) to the dispute (the "Respondent"), (ii) all names appearing on the Mailing List, and (iii) the Board. The Initiating Party and/or the Respondent may be more than one Member.

10.6.3 Form of Notice; Appointment of Panel. The Notice shall be in a form approved by the Board, and shall, at a minimum, describe: (i) the nature of the dispute; (ii) a statement of

7.2.1.2 For disputes regarding other matters, the President shall appoint one (1) or more employees of SWRTA Members who have received mediation training or, if requested by the disputing Members, a professional mediator outside of SWRTA, to facilitate a resolution of the issue by the disputing Members.

7.2.2 Within ten (10) working days of the appointment by the President, the mediator(s) and disputing Members shall meet and attempt to negotiate a resolution of the dispute, following a timetable set out by the mediator. The cost of mediation, including the mediator's reasonable fees and expenses, shall be borne equally by the disputing Members. The mediator shall have no authority to impose a resolution upon the disputing Members, but shall serve only as a facilitator to provide peer review and to support good faith negotiations and resolution of the dispute.

7.2.3 Settlement positions taken by the disputing Members during the course of the negotiations shall be deemed confidential and shall not be introduced as evidence by the opposing Member in any subsequent arbitration, FERC proceeding or litigation concerning the same or related dispute.

7.2.4 If all issues involved in the dispute are not resolved in the manner specified in this Section 7.2 within ninety (90) calendar days or other mutually agreed-to period, after appointment of the mediator, then any unresolved issues will be resolved as follows: (i) upon mutual agreement, the disputing Members will follow the arbitration process set forth in Section 7.3 hereof; or (ii) the complaining Member shall file the dispute with FERC under the FPA for resolution. The provisions of this Section 7.2 are conditions precedent to all other methods of dispute resolution

12.2 Arbitration Process.

12.2.1 Within 14 days of a disputing Member's request that the arbitration process be commenced, each disputing Member shall submit a statement in writing to the other disputing Members, which statement shall set forth in reasonable detail the nature of the dispute, the issues to be arbitrated, and the proposed Award sought through such arbitration proceedings. To the extent disputing Members do not agree on the terms of a required contract for transmission service, each submittal shall include proposed contract language for those issues in dispute. These statements shall constitute the sole submittal of statements for arbitration. A summary of such statement of issues and a brief description of the services sought, including the information required in 18 CFR § 36.1(b)(1), shall be published by the Manager in the Association's newsletter or electronic bulletin board.

12.2.2 Within ten days following the submission of their statements, the disputing Members shall select an Arbitrator. If the disputing Members cannot agree upon an Arbitrator, the disputing Members, by Membership classification, shall take turns striking names from a list of ten qualified individuals supplied by the Arbitration Committee

10.3.2 Collaborative Discussion. Within 5 business days of receipt of an Impasse Notice, disputing Members shall commence the Collaborative Discussion process. Such process shall not exceed 15 days except as mutually agreed to by such Members. Disputing Members shall engage in at least one Collaborative Discussion regarding such matters. Except as otherwise mutually agreed to by such Members, all communication and information resulting from Collaborative Discussions shall be confidential and non-binding for future proceedings and all other purposes. If any matters remain in dispute at the end of the 15 days or such other time period mutually agreed to by such Members, any Member involved in the dispute may submit such matters to a Binding Arbitration Proceeding in accordance with Section 10.6 (subject to the provisions of Section 10.5 regarding FERC Determination Matters) unless such Members mutually agree to utilize mediation pursuant to Section 10.4 or some other form of dispute resolution.

10.4 **Mutually Agreed to Mediation.** If following the completion of the procedures outlined in Section 10.3 the disputing Members are still in dispute, any disputing Member may submit all matters (excluding those matters identified in Sections 10.2.2 and 10.2.3) to a Binding Arbitration Proceeding in accordance with Section 10.6. However, prior to initiating a Binding Arbitration Proceeding, the disputing Members may by mutual agreement elect to use mediation to resolve their dispute before initiating a Binding Arbitration Proceeding in accordance with Section 10.6.

Within 5 business days (or such other time period as mutually agreed to) after the selection by the disputing Members of a mediator from the WATSCO list of arbitrators prepared pursuant to Section 10.7.1 or other mutually agreed to mediator, each disputing Member shall separately submit in writing a statement of the issues that have been agreed upon and the issues still in dispute. Within 5 business days after receipt of such statements the mediator will mediate discussions between or among the Members. The mediator shall be available to hear all sides of issues and disputes and shall be free to suggest resolution, but shall have no authority to bind any Member. Except as otherwise mutually agreed to by such Members, all communication and information resulting from mediation shall be confidential and non-binding for future proceedings and all other purposes. If any matters remain in dispute at the end of 30 days or such other time period mutually agreed to by such Members, any Member involved in the dispute may submit those matters to a Binding Arbitration Proceeding in accordance with Section 10.6, subject to the provisions of Section 10.5 regarding FERC Determination Matters.

10.5 **Determination of FERC Determination Matters.** Following Collaborative Discussion and/or mediation:

10.5.1 Agreement All Matters Subject to Dispute Are FERC Determination Matters; Refer to FERC. If the disputing Members agree that (i) all matters in dispute are FERC Determination Matters or (ii) certain matters in dispute are FERC Determination Matters and all other

7.2 Mediation

7.2.1 One (1) or both disputing Members shall submit a written request, including a written description of the matter under dispute, to the President of the Board for appointment of one (1) or more impartial mediators to provide peer review and aid the disputing Members on an ad hoc basis to reach a mutually acceptable resolution of the dispute. The President shall send a copy of the written description of the matter under dispute to the other disputing Member and to all other Members and shall appoint the mediator(s) within ten (10) working days of receipt of the request. In appointing the mediator(s), the President shall utilize the following guidelines:

7.2.1.1 For disputes regarding technical or engineering matters, the President shall appoint one (1) or more members of the Planning Committee who have knowledge of the matter under dispute and the affected transmission system to provide impartial peer review and to facilitate a resolution of the issue by the disputing Members.

10.2.3 Matters Not Subject to Dispute Resolution Procedure. Notwithstanding any other provision in the Bylaws to the contrary, the following matters shall not be subject to the Dispute Resolution Procedure under these Bylaws:

(i) All executed contracts, including disputes thereunder, and grievances over performance occurring prior to the effective date of these Bylaws;

(ii) Legitimacy of any Transmission Requester's request for transmission service pursuant to Section 5 and the applicable Appendix A;

(iii) Any issues related to ownership of facilities in connection with transactions outside of these Bylaws;

(iv) Choice of planning methodologies, models or tools used by a Member, except as to the Consistent Application thereof or consistency with Prudent Utility Practice;

(v) Compensatory damages with respect to any matter under these Bylaws;

(vi) Applicable rate of return or a reasonable similar charge used by a Member in pricing, provided that such rate of return or other charge is accepted or ordered by a Regulatory Authority; and

(vii) Local, state or federal Regulatory Authority mandates, court orders or decisions, and Member actions in compliance with such mandates, orders or decisions.

10.3 **Initial Steps in Dispute Resolution Procedure.** The steps outlined in this Section 10.3 shall be used in an attempt to resolve any dispute that may arise out of any matter set forth in Sections 10.2.1 and 10.2.2.

10.3.1 Determination of Impasse. Except as otherwise mutually agreed to by the Members involved in a dispute regarding any matter subject to the Dispute Resolution Procedure, any such dispute which is unresolved between or among Members may be declared at an impasse (subject to the time frames provided in the applicable Appendix A hereto) by any Member involved in the negotiation by serving written notice ("Impasse Notice") to the other Members to the negotiations; provided however, with regard to any Member's alleged failure to comply with or discharge its obligations under these Bylaws, no Member may declare an impasse (unless specifically provided otherwise in the Bylaws) regarding such alleged failure during the time period allotted to such Member in the Bylaws to comply with or discharge such obligation.

(viii) The determination of whether a proposed project described in Section 4.3 meets the reliability criteria described in Section 4.2 would impairs service to a Member's Planned Native Load or unreasonably impair the continued reliability (based upon consistently applied NERC, WSCC and an affected Member's reliability criteria and guidelines) of the any Member's electric system or reduces pre-existing transfer capabilities of Members' systems; and

(ix) The determination of costs associated with Incremental Additions and other matters relating to Incremental Additions set forth in Section 5.4.

10.2.2 Matters Not Subject to a Binding Arbitration Proceeding But Which Are Subject to Collaborative Discussion/Mediation. Notwithstanding any other provision in the Bylaws to the contrary, the following matters (except as otherwise noted in this Section 10.2.2) under these Bylaws shall not be subject to a Binding Arbitration Proceeding but shall be subject to Collaborative Discussion and, if applicable, mediation under the Dispute Resolution Procedure:

(i) The selection of the physical means (with regard to existing facilities) or Incremental Additions by which a Transmission Provider provides transmission service to a Transmission Requester provided that the cost of such transmission service is no greater than the cost would have been had the lowest cost reasonable alternative been selected;

(ii) Published provisions of reliability criteria, standards and guidelines of WSCC and NERC;

(iii) The reliability criteria, standards, and guidelines of a Member which were published as of January 1, 1993 and subsequent changes made pursuant to changes in WSCC and NERC criteria, standards and guidelines; provided that such criteria, standards and guidelines are Consistently Applied;

(iv) Members' planning assumptions, processes and methods adopted through state public utility commission, state energy commission or other Regulatory Authority proceedings (or falling within a Zone of Reasonableness established by the Planning Committee), provided that such planning assumptions, processes and methods are Consistently Applied, and further provided that in so far as such assumptions, processes and methods are otherwise challengeable at FERC under existing rules and regulations they remain challengeable at FERC. Nothing herein shall be construed as preventing a Member from bringing such a challenge before FERC; and

(v) Any other matters stated elsewhere in these Bylaws which are not subject to a Binding Arbitration Proceeding.

10.2 Scope of Matters Subject to Dispute Resolution Procedure. Except as specifically provided in Sections 10.2.2 and 10.2.3, all disputes arising out of any matter relating to these Bylaws are subject to the Dispute Resolution Procedure. The partial listing of matters subject to the Dispute Resolution Procedure set forth in Section 10.2.1, and the failure to list all other matters subject to the Dispute Resolution Procedure (other than those excluded in Sections 10.2.2 and 10.2.3) shall not in any way be construed as a limitation regarding matters subject to the Dispute Resolution Proceeding.

10.2.1 Matters Subject to Dispute Resolution Procedure. Matters subject to the Dispute Resolution Procedure (except as noted in this Section 10.2.1) shall include, but not be limited to:

(i) Amounts and location of Available Transmission Capacity;

(ii) Ownership of facilities and Ownership-Like Rights;

(iii) Prices, terms and conditions of transmission service (including any rate or rate methodology/design) provided in accordance with Section 5 and Appendix A of these Bylaws;

(iv) The Consistent Application of NERC, WSCC and Member reliability criteria, standards, operating procedures, and guidelines;

(v) Changes in Member reliability criteria, standards, operating procedures, and guidelines made after January 1, 1993, excluding changes made pursuant to NERC or WSCC reliability criteria, standards or guidelines;

(vi) A Transmission Provider's planning assumptions, methods and processes not adopted through state public utility commission, state energy commission or other Regulatory Authority proceedings;

(vii) Changes which result in a Transmission Provider's planning assumptions, methods and processes adopted through state public utility commission, state energy commission or other Regulatory Authority proceedings being outside a Zone of Reasonableness established by the Planning Committee; provided however, until a Zone of Reasonableness is established, a Transmission Provider's planning assumptions, methods and processes which are changes to those adopted through state public utility commission, state energy commission or other Regulatory Authority proceedings will be subject to the Dispute Resolution Procedure with the Transmission Provider's planning assumptions, methods and processes given a rebuttable presumption of reasonableness;

7. DISPUTE RESOLUTION:

7.1 Applicability

Members shall make best efforts to settle all disputes arising out of the application of these Bylaws. In the event any such dispute is not settled through negotiation, Members shall utilize the following dispute resolution procedures. Additionally, these procedures may be utilized in a dispute over transmission access between a Member and a non-member, so long as both parties agree in writing to follow the procedures. A Member's failure to comply with the provisions of this Section 7 shall entitle the other disputing Member to recover all its costs and attorneys' fees incurred in any proceeding commenced and which by intent or consequence circumvents the dispute resolution provisions of this Section 7.

12. DISPUTE RESOLUTION.

12.1 Preconditions to Arbitration.

12.1.1 Members shall make best efforts to settle all disputes associated with transmission access or services, including but not limited to, disputes concerning amounts and location of Available Transmission Capacity, need for and costs of Incremental Facilities, or costs, prices, and terms and conditions of transmission service. In the event any such dispute is not settled, any disputing Member may request in writing that the Manager appoint an impartial facilitator from the Association membership to aid the disputing Members in reaching a mutually-acceptable resolution to the dispute and such appointment shall be made within ten days. The facilitator and representatives of disputing Members with authority to settle the dispute shall meet within 21 days after the facilitator has been appointed to attempt to negotiate a resolution of the dispute. With the consent of all disputing Members, a resolution may include referring the matter to a technical body (such as a WSCC Technical Advisory Panel) for resolution or an advisory opinion.

12.1.2 If the disputing Members have not succeeded in negotiating a resolution of the dispute within 30 days after first meeting with the facilitator pursuant to Paragraph 12.1.1, such Members shall be deemed to be at impasse and any such disputing Member may commence the arbitration process.

12.1.3 Disputes related to the interpretation or performance of treaties or executed agreements or service schedules that have been approved or accepted for filing by the FERC shall not be subject to Arbitration under this Governing Agreement unless otherwise agreed by the disputing Members. Disputes involving only Members who are also members of a Subregional Coordination Group whose governing documents provide for a dispute resolution mechanism shall be resolved in accordance with such dispute resolution mechanism.

DISPUTE RESOLUTION

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10. DISPUTE RESOLUTION PROCEDURE:

10.1 Intent of Dispute Resolution Procedure. It is intended that these Bylaws provide a process for resolving transmission-related disputes that is more efficient, less costly, and less time-consuming than resolving such disputes through the FERC administrative process or through civil litigation. The Dispute Resolution Procedure should not be used to make policy-related decisions (such as pricing methodology not previously approved by FERC, including opportunity costs pricing methodology), retail wheeling, and stranded investment recovery or revenue requirement protection methodology). Policy-related decisions regarding FERC-jurisdictional matters properly reside with FERC, and a Member's right to go to FERC regarding such policy-related decisions is preserved as a FERC Determination Matter as specifically provided in these Bylaws. Access to FERC for dispute resolution of any non-FERC Determination Matter which is the subject of a Binding Arbitration Proceeding is provided by allowing an appeal of arbitrated issues as specifically provided in this Section 10. It is intended that all applicable means and procedures set forth in these Bylaws shall be utilized by the Members to resolve all Bylaws-related matters (except as provided in Sections 10.2.2 and 10.2.3) before going to FERC with FERC-jurisdictional matters.

The Dispute Resolution Procedure includes Collaborative Discussion, mediation and a Binding Arbitration Proceeding. It is intended that efforts to resolve disputes (except as provided in Sections 10.2.2 and 10.2.3) always use Collaborative Discussion, and upon mutual agreement of the Members involved in such dispute, mediation can be utilized prior to submitting the dispute to a Binding Arbitration Proceeding. With respect to any matter under these Bylaws, each Member involved in negotiations with any other Member shall make good faith efforts to settle any disputes which may arise. Nevertheless, in the event any such dispute is not settled, each such Member agrees that any such dispute, except as hereinafter specifically described, shall be subject to the Dispute Resolution Procedure as set forth in this Section 10, and any such Member may, after good faith efforts to resolve the dispute, declare the dispute at an impasse and commence the Dispute Resolution Procedure.

DISPUTE RESOLUTION

5.9.5 Financing of New Facilities. Any Member who funds new transmission facilities with tax-exempt financing undertaken after the date the Member joins WATSCO, shall, at no additional cost to such Member unless reimbursed by other Members, undertake all reasonable actions to minimize: (i) any restrictions on a Transmission Requester's access to such facilities caused by the tax-exempt financing; and (ii) any increase in the price of transmission service resulting from the refinancing, reconfiguring, or otherwise restructuring of such tax-exempt debt in order to provide service to a Transmission Requester.

cost of refinancing, reconfiguring or otherwise restructuring such tax-exempt debt or such other actions undertaken to remove such impairment such that the requested service could be provided. Such costs shall include, among other things, costs associated with (i) the loss of exclusion from federal gross income of interest paid (or to be paid) on any tax-exempt debt issued, or expected to be issued, by (or for the benefit of) the Transmission Provider regarding facilities necessary to provide such requested transmission service, and (ii) the loss of deductibility of interest expense associated with interest paid (or to be paid) on any such tax-exempt debt. If the Transmission Requester agrees to pay to the Transmission Provider such costs, in addition to payment of all other costs as provided under these Bylaws, the Transmission Provider shall be required to provide the requested transmission service in accordance with the provisions of these Bylaws. If the Transmission Requester does not agree to pay such costs to the Transmission Provider, the Transmission Requester may request, and the Transmission Provider shall provide, transmission service utilizing Incremental Additions in accordance with these Bylaws.

5.9.4 Determination of Cost of Refinancing. If, after exercising due diligence to determine the lowest reasonable cost of refinancing, reconfiguring or otherwise restructuring such tax-exempt debt or such other actions undertaken to remove such impairment such that the requested service could be provided, the Transmission Provider is unable to determine the amount of such costs with reasonable accuracy, the Transmission Provider's obligation to provide the requested service shall terminate; provided, however, that such obligation to provide the requested service shall not terminate in the event that the Transmission Requester posts a bond of sufficient size or provides other assurances that it shall fully compensate the Transmission Provider for those additional costs as they become known. If the Transmission Requester posts such bond or provides such other assurances, or said costs are subsequently determined with reasonable accuracy, the Transmission Requester shall have the option of compensating the Transmission Provider for such costs in which case the Transmission Provider shall provide the requested transmission service in accordance with the provisions of these Bylaws. If the Transmission Requester determines not to post such a bond or provide other assurances that it shall fully compensate the Transmission Provider for such additional costs, the Transmission Requester may request, and the Transmission Provider shall provide, transmission service utilizing Incremental Additions in accordance with these Bylaws.

TAX EXEMPT FINANCING

WATSCO

5.9 Tax-Exempt Financing.

5.9.1 No Impairment of Tax-Exemption. Notwithstanding any other provision of these Bylaws except the provisions of Sections 5.9.3 or 5.9.4, no Transmission Provider shall be required to provide transmission service to a Transmission Requester in a manner that would (i) impair the exclusion from federal gross income of interest paid (or to be paid) on any tax-exempt debt issued, or expected to be issued, by (or for the benefit of) the Transmission Provider, or (ii) impair the deductibility of interest expense associated with interest paid (or to be paid) on any such tax-exempt debt. If no such impairment would occur, a Transmission Provider shall be required to provide transmission service to a Transmission Requester as otherwise provided in these Bylaws.

5.9.2 Nationally Recognized Bond Counsel/Private IRS Letter Ruling. At the request of the Transmission Requester, the Transmission Provider shall consult with nationally recognized bond counsel of its choice to obtain advice (which may include an opinion) regarding the extent, if any, of the impairment. If such bond counsel initially indicates that impairment would occur, the Transmission Provider shall so advise the Transmission Requester. The Transmission Requester may request, and the Transmission Provider and its bond counsel shall attend, a meeting to fully discuss the basis of such bond counsel's position that impairment would occur. Upon the request, and at the cost, of the Transmission Requester, the Transmission Provider shall instruct its bond counsel to provide assistance to the Transmission Requester regarding Regulatory Authority inquiry into such impairment. In addition, the Transmission Requester may request the Transmission Provider, and the Transmission Provider shall prepare and submit, a request to the Internal Revenue Service for a private letter ruling seeking clarification of the extent (if any) of the impairment. If the Transmission Provider receives a bond counsel opinion and/or Internal Revenue Service private letter ruling pursuant to this Section 5.9.2, a copy of such opinion and/or private letter ruling shall be provided to the Transmission Requester. The Transmission Requester shall reimburse all reasonable costs incurred by the Transmission Provider in seeking such bond counsel consultation, advice, assistance, opinion and/or private letter ruling.

5.9.3 Transmission Service Causes Impairment. If, based on consultation with nationally recognized bond counsel or the Internal Revenue Service's private letter ruling, the Transmission Provider determines that compliance with a Transmission Requester's transmission service request would cause such impairment to occur, the Transmission Provider shall determine and provide to the Transmission Requester the Transmission Provider's estimate of the lowest reasonable

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10. TAX EXEMPT FINANCING:

Notwithstanding any other provision of these Bylaws, no Transmitting Member shall be required to provide transmission service to a Requesting Member when to do so would violate any law or covenant restricting the use of transmission facilities funded by tax exempt financing. A Transmitting Member shall undertake all reasonable actions to minimize any such restriction on transmission access to other Members or any increase in the price of transmission service to other Members resulting from the application of the legal restriction. In addition, whenever a Transmitting Member determines that a Requesting Member's request for transmission service may cause a violation of a law or covenant regarding tax exempt financing, the Transmitting Member shall determine the lowest reasonable cost of refinancing, renegotiating or removing the restriction by other means. If the Requesting Member elects to compensate the Transmitting Member for such cost, then the Transmitting Member shall be obligated to remove the restriction.

WRTA

10.7 Tax Exempt Financing. Notwithstanding any other provision of this Governing Agreement, no Transmission Provider shall be required to provide transmission service to a Transmission User when to do so would: (i) impair the exclusion from federal gross income of interest paid (or to be paid) on any tax-exempt debt issued, or expected to be issued, by (or for the benefit of) the Transmission Provider, or (ii) impair the deductibility of interest expense associated with interest paid (or to be paid) on any such tax-exempt debt. A Transmission Provider shall undertake all reasonable actions to minimize any such restriction on transmission access to other Members or any increase in the price of transmission service to other Members resulting from such impairment. In addition, whenever a Transmission Provider determines that a Transmission User's request for transmission service may cause such impairment, the Transmission Provider shall determine the lowest reasonable cost of refinancing, renegotiating or removing the restriction by other means. If the Transmission User agrees to compensate the Transmission Provider for such cost, then the Transmission Provider shall be obligated to remove the restriction. Any Member who funds new transmission facilities with tax-exempt financing undertaken after the date the Member joins the Association shall, at no additional cost to such Member unless reimbursed by other Members, undertake all reasonable actions to minimize (i) any restrictions on a Transmission User's access to such facilities caused by the tax-exempt financing; and (ii) any increase in the price of transmission service resulting from the refinancing, reconfiguring, or otherwise restructuring of such tax-exempt debt in order to provide service to a Transmission User.

TAX EXEMPT FINANCING

5.5.4 Rights Preserved Under FPA Regarding Non-WATSCO Transmission Service Contracts: No Impact Regarding Pending Dispute Resolution or Transmission Requests. No Member's rights to (i) file a rate schedule, tariff or Generic Tariff under Section 205 of the FPA regarding transmission service to be provided without regard to and not in accordance with these Bylaws or (ii) oppose such filing of a rate schedule, tariff or Generic Tariff under the FPA, shall be abridged or affected by these Bylaws. Except as otherwise may be provided in an effective rate schedule, tariff or Generic Tariff filed without regard to and not in accordance with these Bylaws, no Member's rights to (i) file a rate schedule amendment, tariff amendment or Generic Tariff amendment under Section 205 of the FPA to modify provisions of an effective rate schedule, tariff or Generic Tariff (including a change in rates or rate methodology), or (ii) oppose such filing of a rate schedule amendment, tariff amendment or Generic Tariff amendment under the FPA, shall be abridged or affected by these Bylaws. The filing of a rate schedule amendment, tariff amendment or Generic Tariff amendment with FERC under Section 205 of the FPA shall have no (i) FERC-precedential value with respect to any Binding Arbitration Proceeding initiated prior to the notice provided for in Section 5.5.5 or the filing of such rate schedule amendment, tariff amendment or Generic Tariff amendment or (ii) adverse impact on a Transmission Requester which initiates any request for transmission service under these Bylaws prior to the filing of such generic tariff.

5.5.5 Notification of Proposed FERC Filing; Collaborative Discussions. No Member shall file a rate schedule amendment, tariff amendment, Generic Tariff or Generic Tariff Amendment as provided in Section 5.5.4 without (i) providing written notification, at least 30 days prior to making such filing, to all Members potentially affected by such proposed filing, and (ii) participating in Collaborative Discussions or mediation (as provided in Section 10.3.2 or 10.4) regarding such filing with other Members wishing to engage in such discussions during such 30-day notice period. Such written notification shall describe the essential elements of the proposed Generic Tariff or the projected changes which would result from the proposed rate schedule amendment, tariff amendment or Generic Tariff amendment, as the case may be. Nothing in these Bylaws shall be construed to subject such filing to the Binding Arbitration Procedure.

11.6 **Bylaws Not a Tariff or Rate Schedule for Provision of Transmission Service.** These Bylaws are not intended to be, and shall not be construed or held to be, a FERC rate schedule or tariff for the provision of transmission service. The provision of any services and the terms and conditions thereof, as contemplated by these Bylaws, shall be implemented through separate written transmission service contracts which will be filed with FERC to the extent it has jurisdiction over the Transmission Provider.

PRICING PRINCIPLES\PRACTICES

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5.5 **Determination of Pricing and Other Terms and Conditions of Transmission Service.** To the extent consistent with the FPA, FERC regulations, policies and precedents (including but not limited to pricing methodologies) and these Bylaws, the pricing of transmission services provided pursuant to contracts entered into in accordance with these Bylaws shall be cost-based and shall not be at the expense of the investors in, customers or owners of the Member providing such services.

5.5.1 Negotiate Rates, Terms and Conditions. Following the process of requesting transmission service in accordance with this Section 5 and the applicable Appendix A hereto, the Transmission Provider and the Transmission Requester shall, as the next step, negotiate the rates (including the methodology and rate design used to calculate the rates) and other terms and conditions of the transmission service to be provided.

5.5.2 Agreement on Rates, Terms and Conditions. If the Transmission Provider and the Transmission Requester agree upon the rate, rate methodology/design and other terms and conditions of service:

5.5.2.1 With respect to a Type 1 Transaction, the Transmission Provider and the Transmission Requester shall (i) execute a contract to set forth and implement the agreed upon rate, rate methodology/design and other terms and conditions of service, and (ii) file with FERC a rate schedule or rate schedule amendment consisting of such rate, rate methodology/design and other terms and conditions of service as provided in Subpart B of Part 35 of Title 18, C.F.R. Both the Transmission Provider and the Transmission Requester shall fully support such filing before FERC; or

5.5.2.2 With respect to a Type 2 Transaction, the Transmission Provider and the Transmission Requester shall execute a contract to set forth and implement the agreed upon rate, rate methodology/design, and other terms and conditions of service.

See WATSCO §§ 3.45 and 3.46 in the Definitions Section for definitions of Type 1 and Type 2 Transactions.

5.5.3 Failure to Agree - Initiate Dispute Resolution Procedure. If any rate, rate methodology/design, or any other term or condition is not agreed to by the Transmission Provider and the Transmission Requester within the appropriate time period as provided in Section I of the applicable Appendix A (or such longer period as is agreed to by the Transmission Requester and the Transmission Provider), either the Transmission Provider or the Transmission Requester may initiate the Dispute Resolution Procedure in accordance with Section 10.

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5. PRICING PRINCIPLES:[1]

Pricing for transmission service provided pursuant to these Bylaws shall comply with the principles of Section 212(a) of the FPA and shall reflect the underlying principles that rates, charges, terms and conditions for transmission services provided pursuant to these Bylaws shall ensure that, to the extent practicable, costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the Requesting Member and not from the Transmitting Member's existing wholesale, retail, and transmission customers. Any Member or, subject to Board approval, SWRTA as an organization may, from time to time, request through, inter alia, a petition for declaratory ruling, or request for rulemaking, that FERC find that a particular form of transmission pricing complies with the principles of Section 212(a) of the FPA. Nothing in these Bylaws shall preclude Transmitting and Requesting Members which have negotiated a transmission service agreement pursuant to a request for service under these Bylaws from mutually agreeing to transmission pricing that expands upon established FERC precedent, so long as the agreement is filed with FERC, if required, pursuant to Sections 205 of the FPA and the negotiated price complies with the principles of Section 212(a) of the FPA.

[1] If RTGs are to be the functional equivalent of Sections 211-213 of the FPA, will FERC require prices for transmission service provided voluntarily pursuant to RTG Bylaws to comply with Section 212(a), or do the pricing principles stated in Section 212(a) apply only to transmission service ordered by FERC under to Section 211?

WRTA

11. PRICING.

Pricing of transmission service by a Transmission Provider in response to any request for transmission service shall utilize pricing procedures and methodologies that are consistent with the FPA and then-applicable standards and policies of the FERC. Transmission Providers in Canada or Mexico may rely upon pricing policies of regulatory bodies other than the FERC if such policies are no less favorable to Transmission Users than those of the FERC. Notwithstanding the foregoing, any Member may, from time to time, request through a petition for declaratory ruling, or request for rulemaking, that the FERC find a particular form of transmission pricing just and reasonable; provided, however, pending the resolution of such petition or request, established policies shall govern and provided further, any Member may challenge in a future Arbitration whether such declaratory ruling represents FERC-adopted policy regarding a then-pending request for transmission service.

PRICING PRINCIPLES/PRACTICES

RETAIL WHEELING

WATSCO

5.10 **Prohibition on Retail Wheeling and Sham Wholesale Transactions.** Nothing in these Bylaws (including but not limited to the outcome of any Binding Arbitration Proceeding) shall require any Member to provide requested transmission service that will be used for, or will be assigned for, wheeling electric energy (i) directly to an ultimate consumer or (ii) to, or for the benefit of, an entity if such electric energy would be sold by such entity directly to an ultimate consumer, except as permitted consistent with Section 212(h) of the FPA. Nothing in these Bylaws shall prohibit any Member (in its sole and absolute discretion) from providing transmission service that will be used for, or will be assigned for, wheeling electric energy (i) directly to an ultimate consumer or (ii) to, or for the benefit of, an entity if such electric energy would be sold by such entity directly to an ultimate consumer.

See WATSCO § 5.6.2, No Assignments for Retail Wheeling, in Transmission Service Section

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8. COMPLIANCE WITH SECTION 212(H) OF THE FPA:

No Member shall be required to comply with an arbitration decision which requires the transmission of electric energy under circumstances where FERC is precluded from ordering transmission services pursuant to Section 212(g) or 212(h) of the FPA.

WRTA

13. NO MANDATORY RETAIL WHEELING.

No Arbitrator shall select and no Member consents to an Award which requires the transmission of electric energy under circumstances where the FERC is precluded from ordering transmission services pursuant to Subsection 212(h) of the FPA.

RETAIL WHEELING

RECIPROCAL AGREEMENTS

WATSCO

ESTABLISHING RECIPROCAL AGREEMENTS WITH OTHER RTGs: Members are willing to enter into good faith negotiations with entities which are interested in forming, or have formed, a regional transmission group (an "RTG"), with the intent of establishing agreements creating reciprocal rights and obligations among WATSCO Members and members of such other RTGs.

Such reciprocating rights and obligations will include, but not be limited to, establishment of mutual rights to (i) obtain or provide wholesale transmission access priced consistent with the FPA and FERC policies and regulations; (ii) resolve disputes between the Members of the different RTGs issuing dispute resolution procedures that do not require first recourse to FERC, and (iii) provide for coordinated interregional transmission planning for system enhancements and additions.

SWRTA

14.10 Coordination Among RTGs

The Board shall establish policies and procedures for interface with and coordination of activities, benefits and obligations between SWRTA and other RTGs and regional planning groups.

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10.6 Requests Involving Only Members of Subregional Coordination Groups. If a request for transmission service involves only Members who are also members of a Subregional Coordination Group and the governing documents of such Subregional Coordination Group provide for a process for requesting transmission service, the process of the Subregional Coordination Group, as opposed to that set forth in this Section 10, shall be followed. To the extent the governing documents of the Subregional Coordination Group establish different principles regarding the provision of transmission service, or the pricing thereof, or the granting of ownership or Ownership-Like Rights in facilities, than those of the Association, the principles of the Subregional Coordination Group shall govern only as among members of the Subregional Coordination Group.

RECIPROCAL AGREEMENTS

of the bid-conducting Member) shall be deemed a written transmission request under this Appendix A as of the date the written wheeling study request is received by the wheeling Member (which is the Notice Date). The priority afforded such Notice Date, however, shall be lost if an award of said bid is not made within a reasonable period of time from the date the bid-conducting Member receives the results of the written wheeling study by the wheeling Member.

The Planning Committee may adopt rules and guidelines, including guidelines for determining reasonable time periods in Section IV (C.1 and 2) above, to implement the foregoing principles.

V. Substantial Change to Transmission Request/Loss of Priority.

In the event that a Transmission Requester unilaterally makes a substantial change to a transmission service request submitted under Section 5 and this Appendix A, said revised request shall lose its Notice Date under Section III above (and the resulting priority), and shall be deemed a new request as of the date that the Transmission Provider receives the Transmission Requester's written request to substantially revise the original request. The Planning Committee may adopt rules and guidelines regarding what constitutes a "substantial change" to a transmission service request.

VI. Notice of WATSCO Agreements to Planning Committee

Members are encouraged to notify other Members or entities likely to be affected by the implementation or operation of proposed agreements under WATSCO. To facilitate openness and trust among Members, each Member shall ensure the Planning Committee receives a copy of each WATSCO agreement that is entered into, within seven days of execution of the agreement. The Planning Committee shall adopt reasonable rules and guidelines for notifying other Members of such WATSCO agreements.

The notice requirements of this Section VI, or under the rules and guidelines adopted by the Planning Committee pursuant to this Section VI, shall not be deemed to establish a legal or equitable duty or obligation on the part of a Member to notify another Member or non-Member under this Section VI, nor shall any non-Member be deemed a third party beneficiary as a result of this Section VI.

etc.) engineering/economic studies of Incremental Additions resulting from requests requiring Incremental Additions on the same part of a Transmission Provider's system shall be included in a common engineering/economic study. However, to the extent that such engineering/economic study results in, or may result in, a higher cost of service to the original Transmission Requester(s), nothing herein shall prevent such Transmission Requester from requesting at the sole cost of the original Transmission Requester(s), from requesting that the engineering/economic study be broadened to include such considerations. Furthermore, insofar as any Transmission Requester believes that lower cost options for providing the requested service may be available which would not otherwise be included in the engineering/economic study, such Transmission Requester may request and negotiate for the inclusion of additional variations, options, or sensitivities in the engineering/economic study.

B. Member-Initiated Transmission Improvements. If a Member determines to initiate a project improving its transmission facilities rated at 100 kV or above, which is projected to result in an increase of transmission capacity, then such Member shall provide notice to other Members describing the general characteristics of the project. Such notice shall be provided at the earliest point in time, as reasonably determined by such Member, so as to permit other needs to be addressed and the project to be reconfigured, if necessary and appropriate.

C. Competitive Bidding Process of Member. It is understood that Members may from time to time engage in a competitive bidding process for resource acquisition. In such event, the following principles shall apply:

1. Commencing at a reasonable time prior to the publishing of the request for proposal (RFP), the bid-conducting Member shall be entitled to set aside for its own resource needs that amount of Available Transmission Capacity that is equal to its total resource solicitation. The bid-conducting Member may set aside that amount of Available Transmission Capacity, on a system-wide basis, until the earliest time the amount and location of transmission capacity that is not needed to accommodate potential winning bids for its own resource solicitation needs can be determined with reasonable certainty.

2. Following receipt of the responsive bids, the bid-conducting Member shall have an on-going obligation, in response to a Member's transmission request, to determine the existence of any Available Transmission Capacity of the bid-conducting Member. The bid-conducting Member shall base its on-going determination upon the best available information regarding the potential winning bids and their likely effect on the bid-conducting Member's Available Transmission Capacity.

3. A wheeling Member shall provide Available Transmission Capacity to Transmission Requesters on a first-in-time basis in accordance with Section III. For purposes of a competitive bidding process, a written request by the bid-conducting Member to a wheeling Member for a wheeling study regarding an out-of-area bid (i.e., a bid from a bidder located external to the control area

Procedure or in the event of delay caused by Uncontrollable Force. The Transmission Requester(s) and the Transmission Provider may also extend such 180-day period by mutual agreement under Section I(B) above.

If the Transmission Requester and the Transmission Provider fail to enter into a transmission service contract within the 180-day period (unless such period is extended by mutual agreement or due to Uncontrollable Force or is tolled by the initiation of a Dispute Resolution Proceeding), then the Transmission Provider shall offer the Available Transmission Capacity to the next Transmission Requester whose pending request was first filed after the subject request (i.e., first come, first served) until the Available Transmission Capacity is fully utilized. Nothing herein shall prohibit the submission of joint transmission requests.

IV. Procedure Regarding Incremental Additions

A. Engineering/Economic Study. In the event an engineering/economic study of Incremental Additions will be necessary to provide requested service as provided in Section I(A.15), then the following shall apply:

1. At the same time as the notification of the Transmission Requester pursuant to Section I(A.15), the Transmission Provider shall also notify the WATSCO Planning Committee. The Planning Committee, or its designee, shall notify all WATSCO Members of the Transmission Provider's determination of the need for Incremental Additions.

2. The notice shall contain, at a minimum: a copy (or detailed description) of the service request; a description of the existing transmission facilities; the estimated Incremental Additions that would be necessary to accommodate the service request based on information supplied pursuant to Section 5 and any other forecasted transmission requirements over that path; and the estimated costs, if available, of such Incremental Additions.

3. Any Member may, within 30 days of the receipt of the notice pursuant to Section IV(A.1), submit a request for transmission service to the Transmission Provider over the same transmission path requiring Incremental Additions and request that an engineering/economic study be undertaken.

4. To the extent that multiple requests are received, and the provision of service requires construction of Incremental Additions at increasing costs of construction, the rights of Transmission Requesters to service regarding such Incremental Additions, which service cost/price is based upon such increasing construction costs, shall be granted on a first-in-time basis regarding the Transmission Requester's request.

5. Consistent with the WATSCO goal of coordinated transmission planning (economies of scale, best use of transmission corridors, minimum environmental impact,

B. Time Periods. Notwithstanding the maximum time periods as provided in this Appendix A, each Member shall make a good faith attempt to perform its respective obligations as expeditiously as possible. The existence of such maximum time periods shall not excuse any Member from making a good faith effort to complete its respective obligations in less time. Except as otherwise provided in this Appendix A, all time periods provided in this Appendix A refer to calendar days.

Any of the time periods provided in Section I(A), however, may, for good cause, be extended by mutual agreement of the Transmission Requester(s) and the Transmission Provider, provided that the extension shall not unduly delay or otherwise unfairly prejudice a competing Member's request. The Transmission Provider shall notify Members with competing requests of any proposed time extension, and the reason(s) therefor. Each Member with a competing request shall be allowed seven days from receipt of the Transmission Provider's notice to determine whether its request may be unduly delayed or unfairly prejudiced by the proposed extension. If a Member with a competing request notifies the Transmission Provider in writing that the extension would likely cause the Member's request to be unduly delayed or unfairly prejudiced, then the written consent to the proposed extension by such competing Member shall be required prior to such proposed extension. The competing Member's written consent, however, shall not be unreasonably withheld.

Transmission Requester(s) shall grant requests for reasonable extensions of time to the Transmission Provider to allow for the study of additional transmission requests from other Members under Section III and I(A.15) or for the study of concurrent requests of a Transmission Requester. Transmission Requester(s) shall not unreasonably withhold permission for reasonable extensions of time to complete such studies.

II. Transmission Study Costs

The Transmission Provider may, at its option, require the Transmission Requester(s) to enter into a contract with the Transmission Provider to compensate it for all or part of the reasonable costs of any study required of the Transmission Provider pursuant to Section I above. Such reasonable costs shall be limited to costs that are directly related to the performance of the study, and shall not include costs that are incurred by the Transmission Provider prior to the study request.

III. Priority of Requests for Transmission Service

Subject to Sections 5.2.1 and 5.2.2, Available Transmission Capacity shall be made available to the Member whose written transmission request is received first in time by the Transmission Provider, provided that the Transmission Requester and Transmission Provider enter into a transmission service contract for the Available Transmission Capacity within 180 days of the receipt by the Transmission Provider of the desire to receive service as provided in Section I(A.6) or I(A.12), as is applicable. Any applicable time periods set forth in this Appendix A, including the 180-day period to complete a service contract, shall be automatically tolled in the event any interested Member declares an impasse and a matter is submitted to the Dispute Resolution

16. Notice of Desire to Pursue Construction. If any Transmission Requester desires to pursue construction of any alternative in the study, the Transmission Requester shall provide written notice to this effect to the Transmission Provider within 60 days of the date it receives the Transmission Provider's notification of the completion of the study pursuant to Section I(A.15).

The Transmission Requester(s) that provide such notice to pursue construction of an alternative and the Transmission Provider shall meet and negotiate in good faith the selection of one alternative to be constructed subject to compliance with the California Environmental Quality Act and any other applicable environmental laws; provided however, in the event no agreement can be reached, the Transmission Provider shall select the alternative to construct, subject to Section 5.4.9.

If all Transmission Requesters fail to provide written notice of a desire to pursue construction of an alternative within the 60-day period, the Transmission Provider's obligation to provide service through the construction of Incremental Additions is discharged. The Transmission Requester may at any time thereafter submit a new request for such service pursuant to Section 5; in such event, the Transmission Provider shall, to the extent possible, use its previous studies to avoid duplicating costs in responding to the resubmitted request.

17. Obtaining Permits and Approvals; Compliance with CEQA. After receipt of the Transmission Requesters' notice of desire to pursue construction of Incremental Additions under Section I(A.16), the Transmission Requester(s) and the Transmission Provider shall agree upon the necessary steps to comply with the California Environmental Quality Act, other applicable environmental laws, and the licenses, permits and approvals, if any, which should be obtained prior to a commitment to construct Incremental Additions and enter into a contract setting forth such agreement and the payment of costs related thereto. Upon completion of these tasks, the Transmission Requester(s) shall provide to the Transmission Provider written notice whether or not to proceed with construction of the Incremental Additions, subject to Section I(A.18), within 60 days of completion of such tasks.

18. Agreement for Construction. Transmission Requester(s) providing notice to proceed with construction of Incremental Additions pursuant to Section I(A.17) shall enter into a contract(s) with the Transmission Provider regarding, among other things: (a) the schedule for the detailed engineering design and cost estimate, regulatory filing (if applicable), additional environmental compliance (if necessary), and the estimated construction period; (b) if applicable, each interested party's allocated share of costs with respect to the Incremental Additions, including costs regarding the detailed engineering design, permits, licenses, regulatory approvals, and construction; and (c) if applicable, any other related transmission service contract(s) required for the requested service.

Subject to the provisions of the contract referred to in the preceding paragraph, the Transmission Provider shall make good faith efforts to complete the detailed engineering design and construction, obtain all necessary regulatory approvals, and place the project in service in a timely manner.

14. Request For Engineering/Economic Study Regarding Incremental Additions. If the Transmission Requester desires to proceed with an engineering/economic study described in Section I (A.13), the Transmission Requester must provide written notice thereof to the Transmission Provider within 30 days of receipt of the Transmission Provider's notice regarding such a study under Section I(A.13).

If the Transmission Requester fails to provide its written notice within the 30-day period, the Transmission Provider's obligation to provide the requested service related to such study shall be discharged. The Transmission Requester may at any time thereafter submit a new request for such service pursuant to Section 5; in such event, the Transmission Provider shall, to the extent possible, use previous studies to avoid duplicating costs in responding to the resubmitted request.

15. Engineering/Economic Study of Incremental Additions. After receipt of the Transmission Requester's notice pursuant to Section I(A.14) requesting the engineering/economic study of construction alternatives for Incremental Additions, the Transmission Provider shall immediately provide notice of such request to the Planning Committee pursuant to Section IV(A.1). After the 30-day notice period set forth in Section IV(A.3) has expired, the Transmission Provider, the original Transmission Requester, and any other Member requesting transmission service pursuant to Section IV(A.3) shall negotiate, within 30 days thereafter: (a) any additional information and the assumptions that are reasonably necessary to conduct the study, and (b) the schedule for completing the study, which shall not exceed 10 months except upon mutual agreement. The Transmission Provider shall estimate the cost of such study and advise all interested parties. If the Transmission Provider requires payment by the Transmission Requesters of all or a portion of the costs of such study, the Transmission Provider shall provide an executable contract to all interested parties within 10 days of the end of the 30-day period referred to above in this paragraph.

The Transmission Provider shall commence the engineering/economic study upon receipt of the additional information, if any, and the executed contract, if any, as each is referred to in the preceding paragraph. If neither additional information or a contract is necessary, the Transmission Provider shall commence the study promptly following the end of the 30-day period provided in the preceding paragraph and shall complete the study within the schedule provided for in the preceding paragraph.

Upon completion of the study, the Transmission Provider shall notify the Transmission Requester(s) in writing, and shall provide the following information: (a) the construction alternatives for the Incremental Additions which were studied; (b) the preliminary estimated cost of constructing each alternative; (c) the rationale for the selection of the preferred alternative; (d) the proposed allocation of costs among the Transmission Requester(s) and the Transmission Provider (if any costs should be allocated to the Transmission Provider) for the preferred alternative; and (e) any applicable transmission service rate information for the preferred alternative.

16. Notice of Desire to Pursue Construction. If any Transmission Requester desires to pursue construction of any alternative in the study, the Transmission Requester shall provide written notice to this effect to the Transmission Provider within 60 days of the date it receives the Transmission Provider's notification of the completion of the study pursuant to Section I(A.15).

The Transmission Requester(s) that provide such notice to pursue construction of an alternative and the Transmission Provider shall meet and negotiate in good faith the selection of one alternative to be constructed subject to compliance with the California Environmental Quality Act and any other applicable environmental laws; provided however, in the event no agreement can be reached, the Transmission Provider shall select the alternative to construct, subject to Section 5.4.9.

If all Transmission Requesters fail to provide written notice of a desire to pursue construction of an alternative within the 60-day period, the Transmission Provider's obligation to provide service through the construction of Incremental Additions is discharged. The Transmission Requester may at any time thereafter submit a new request for such service pursuant to Section 5; in such event, the Transmission Provider shall, to the extent possible, use its previous studies to avoid duplicating costs in responding to the resubmitted request.

17. Obtaining Permits and Approvals; Compliance with CEQA. After receipt of the Transmission Requesters' notice of desire to pursue construction of Incremental Additions under Section I(A.16), the Transmission Requester(s) and the Transmission Provider shall agree upon the necessary steps to comply with the California Environmental Quality Act, other applicable environmental laws, and the licenses, permits and approvals, if any, which should be obtained prior to a commitment to construct Incremental Additions and enter into a contract setting forth such agreement and the payment of costs related thereto. Upon completion of these tasks, the Transmission Requester(s) shall provide to the Transmission Provider written notice whether or not to proceed with construction of the Incremental Additions, subject to Section I(A.18), within 60 days of completion of such tasks.

18. Agreement for Construction. Transmission Requester(s) providing notice to proceed with construction of Incremental Additions pursuant to Section I(A.17) shall enter into a contract(s) with the Transmission Provider regarding, among other things: (a) the schedule for the detailed engineering design and cost estimate, regulatory filing (if applicable), additional environmental compliance (if necessary), and the estimated construction period; (b) if applicable, each interested party's allocated share of costs with respect to the Incremental Additions, including costs regarding the detailed engineering design, permits, licenses, regulatory approvals, and construction; and (c) if applicable, any other related transmission service contract(s) required for the requested service.

Subject to the provisions of the contract referred to in the preceding paragraph, the Transmission Provider shall make good faith efforts to complete the detailed engineering design and construction, obtain all necessary regulatory approvals, and place the project in service in a timely manner.

the notice, the Transmission Provider shall also provide to the Transmission Requester a report based on the transmission studies (including the underlying assumptions) which served as the basis for the Transmission Provider's conclusion(s) regarding the existence of Available Transmission Capacity or the need for Incremental Additions.

12. Transmission Requester's Response When Requested Service Available after Fifty-Day Study. If after the completion of the 50-day study the Transmission Provider indicates the requested service may be partially or wholly provided utilizing Available Transmission Capacity, the Transmission Provider shall provide the Transmission Requester with a Proposed Service Agreement.

The Transmission Requester must notify the Transmission Provider in writing of its desire to receive the service from the Transmission Provider, subject to entering into a mutually agreeable service contract. The Transmission Requester's notice shall be delivered to the Transmission Provider no more than 30 days from the date it receives the Transmission Provider's notice of availability of requested service under Section I(A.11).

The notice shall state whether the Transmission Requester is accepting: (i) the full amount of requested service, which is wholly provided utilizing Available Transmission Capacity; (ii) less than the full amount of requested service, which is provided utilizing Available Transmission Capacity; or, (iii) less than the full amount of the requested service, which is partially provided utilizing Available Transmission Capacity, but the Transmission Requester continues to request the remaining amount of desired transmission service (which will require Incremental Additions - see Section I(A.14)).

If the Transmission Requester fails to provide its written notice within the 30-day period, the Transmission Provider's obligation to provide the requested service related to such 50-day study shall be discharged. The Transmission Requester may at any time thereafter submit a new request for such service pursuant to Section 5; in such event, the Transmission Provider shall, to the extent possible, use its previous studies to avoid duplicating costs in responding to the resubmitted request.

13. Necessity of Engineering/Economic Study. If Incremental Additions are necessary to provide the requested service, the Transmission Provider's notice shall specify whether an engineering/economic study of construction alternatives regarding such Incremental Additions is necessary. If an engineering/economic study is necessary, the Transmission Provider's notice shall specify the scope and estimated cost of such study. The Transmission Provider shall complete such a study within ten months of its commencement.

8. Scope and Cost of Fifty-Day Study Additional Information Required. If a 50-day study is required by the Transmission Provider, the Transmission Provider shall notify the Transmission Requester in writing of the scope and nature of the 50-day study to determine how the requested service can be provided, any additional information required to conduct such study, the reasonable assumptions which will be utilized in the study, and the estimated cost of such study.

9. Notice of Desire to Proceed with Fifty-Day Study. Within 15 days of the date it receives the Transmission Provider's notice of the need for a 50-day study as provided in Section I(A.8), the Transmission Requester shall provide written notice to the Transmission Provider whether the Transmission Requester desires to proceed with such 50-day study.

If the Transmission Requester fails to provide its written notice to proceed with the study within the 15-day period, the Transmission Provider's obligation to conduct the study or provide the requested service related to such study shall be discharged. The Transmission Requester may at any time thereafter submit a new request for such service pursuant to Section 5.

10. Conduct Fifty-Day Study. If the Transmission Requester notifies the Transmission Provider of the desire to proceed with the 50-day study, the Transmission Provider shall advise the Transmission Requester in writing of the assumptions which will be utilized to conduct the 50-day study and any additional information reasonably required from the Transmission Requester in order to conduct the 50-day study. If full or partial payment for such 50-day study is required by the Transmission Requester, the Transmission Provider shall provide to the Transmission Requester an executable contract regarding such study within 10 days of the Transmission Provider's receipt of notice of desire to proceed with such study as provided in Section I(A.9). The Transmission Requester shall have 15 days from its receipt thereof to execute and return such contract to the Transmission Provider. If the Transmission Requester fails to deliver such an executed contract within such 15-day period, the Transmission Provider's obligation to conduct such a study or provide requested service related to such study shall be discharged. The Transmission Requester may at any time thereafter submit a new request for such service pursuant to Section 5.

The Transmission Provider shall commence the 50-day study upon receipt of all information reasonably requested from the Transmission Requester to conduct the study and the executed contract for payment of all or a portion of the costs of such 50-day study. If the Transmission Provider does not require such a contract or additional information, it shall commence the 50-day study upon receipt of the Transmission Requester's notice of desire to proceed with such study as provided in Section I(A.9).

11. Notification When Fifty-Day Study Completed. Upon completion of the 50-day study, the Transmission Provider shall notify the Transmission Requester in writing whether: (a) the requested service may be partially or wholly provided utilizing Available Transmission Capacity without further study; or (b) Incremental Additions are necessary to provide the requested service. As part of

5. Provide Proposed Service Contract if Available Transmission Capacity Exists. If the Transmission Provider notifies the Transmission Requester that the requested service can be partially or wholly provided utilizing Available Transmission Capacity, the Transmission Provider shall provide with such notification a proposed service contract (a "Proposed Service Contract") setting forth, among other things, specifications of the price at which the service would be provided and the applicable terms and conditions of such service. Such specifications shall explain the basis for the charges for each component of service, including the unbundled components of any transmission rate and any other charges.

6. Transmission Requester Response When Available Transmission Capacity Is Available. If the Transmission Provider notifies the Transmission Requester that the requested service can be partially or wholly provided utilizing Available Transmission Capacity, the Transmission Requester must notify the Transmission Provider in writing of its desire to receive service from the Transmission Provider, subject to entering into a mutually agreeable service contract. The Transmission Requester's notice shall be delivered to the Transmission Provider no more than 30 days from the date the Transmission Requester receives the Transmission Provider's notice under Section I(A.5) that service is available.

The Transmission Requester's notice shall state whether the Transmission Requester is accepting: (i) the full amount of requested service, which is wholly provided utilizing Available Transmission Capacity; (ii) less than the full amount of requested service, which is provided utilizing Available Transmission Capacity; or (iii) less than the full amount of the requested service, which is provided utilizing Available Transmission Capacity, but the Transmission Requester continues to request the remaining amount of desired service (which may require Incremental Additions, pending further study).

If the Transmission Requester fails to provide its written notice regarding acceptance of service to the Transmission Provider within the 30-day period provided in this Section I(A.6), the Transmission Provider's obligation to provide the requested service shall be discharged. The Transmission Requester shall then have the right to resubmit its request for such service pursuant to Section 5.

7. Transmission Provider and Transmission Requester Negotiate Service Contract. If the Transmission Requester notifies the Transmission Provider of its desire to receive service in accordance with Section I(A.6) or Section I(A.12), the Transmission Requester and the Transmission Provider shall have a maximum of 180 days from the receipt of such notice by the Transmission Provider to negotiate in good faith a service contract regarding such service (excluding any service to be provided through Incremental Additions or through other means as identified in a 50-day study or and engineering/economic study); provided however, the Transmission Requester or the Transmission Provider may declare an impasse in negotiations and initiate a Dispute Resolution Proceeding at anytime following 60 days from the receipt of such notice.

APPENDIX A - STATE OF CALIFORNIA

TRANSMISSION SERVICE REQUEST PROCESS AND PRIORITY

Except as otherwise provided in this Appendix A, if a term that is defined in the Bylaws is used in this Appendix A, said term shall have the same definition in Appendix A as provided in the Bylaws.

I. Interconnection and/or Transmission Service Request Process

A. Interconnection and/or Transmission Service. The following process shall apply to requests for interconnection and/or transmission service under Section 5 of the Bylaws and, except as specifically provided otherwise, shall be in accordance with the requirements of the final FERC Policy Statement Regarding Good Faith Requests as determined in Docket No. PL 93-3-000, as such requirements may be amended or supplemented from time to time by the FPA or FERC regulations, policies or precedents:

1. Check Submitted with Request; Transmission Provider Date Stamp Each Request Received. Each Member shall include with its request a check to defray the reasonable costs of the Transmission Provider related to the discharge of the Transmission Provider's obligations as set forth in Section I(A.1) through Section I(A.5). The Transmission Provider shall immediately "date stamp" each request on the date of its receipt, which date shall constitute the Notice Date.

2. Confirmation of Receipt of Request; Notification of Insufficient Information. Within 10 days from the Notice Date, the Transmission Provider shall notify the Transmission Requester in writing of (i) the date of receipt of the request by the Transmission Provider and, (ii) if there is insufficient information in the request, what additional information is needed by the Transmission Provider to respond to the request.

3. Response to Request for Additional Information. Upon receipt of a notice of insufficient information in a request, the Transmission Requester shall have 15 days thereafter to provide the Transmission Provider with the additional information. If the Transmission Requester fails to provide the additional information to the Transmission Provider within the fifteen-day period, the Transmission Provider's obligation to provide the requested service pursuant to the related request is discharged. The Transmission Requester may at any time thereafter submit a new request to the Transmission Provider which shall be date stamped by the Transmission Provider with a new Notice Date.

4. Notification of Available Transmission Capacity and/or Need for Fifty-Day Study. Within 15 days from the Notice Date or, in the event insufficient information is provided in the request, within 15 days of the date the Transmission Provider receives the requested information, the Transmission Provider shall notify the Transmission Requester in writing whether: (a) the requested service can be partially or wholly provided utilizing Available Transmission Capacity without further study (assuming the Transmission Provider is reasonably able to make such a determination); or (b) a 50-day study will be required to determine the existence of Available Transmission Capacity or the need, if any, for the construction of Incremental Additions.

5.12 **No Dedication of Facilities.** Except as otherwise specifically provided in these Bylaws regarding ownership rights, no undertaking by a Member under any provision of these Bylaws shall constitute the dedication of the electric system or any portion thereof by the undertaking Member.

5.8 **Curtailment of Transmission Services.** Curtailment of transmission service provided in accordance with these Bylaws shall be as set forth in the contract for service and shall be pro rata among parties possessing the same type of firm entitlements, whether such firm entitlements are through ownership or transmission service. Whenever a curtailment on a given path is required, the curtailment shall be allocated on a pro rata basis based on the firm entitlements (irrespective of the amount scheduled or the type (firm or non-firm) of schedules) to the transfer rating of the line or path, as appropriate.

By mutual agreement of the Members under a separate contract for transmission service, curtailment provisions may vary from this priority and prices for transmission service may reflect this variation. Power flow problems associated with any system contingencies will be handled through reasonable curtailment provisions consistent with this Section 5.8.

In the event continuity of service within the control area which is providing the transmission service is being jeopardized, the control area operator shall take whatever action it deems necessary in accordance with Prudent Utility Practice in order to terminate the system jeopardy condition and, in connection therewith, to preserve and maintain the safety, integrity and operability of the transmission system utilized to provide transmission service, to maintain to the maximum extent practicable the availability of such transmission system, to protect the health and safety of employees and the public, and to minimize any adverse environmental effects. As used in this Section 5.8, "system jeopardy" shall mean an unplanned event or circumstance or a series of events or circumstances which results in, or threatens to result in, termination of continuity of service on the transmission system providing the transmission service.

§ 5.9 Tax-Exempt Financing; See Tax Exempt Financing Section

§ 5.10 Prohibition on Retail Wheeling and Sham Wholesale Transactions; See Retail Wheeling Section

5.11 **Request Service Under Bylaws In Lieu Of Request for Service Under The FPA.** Except as provided elsewhere in these Bylaws or as mutually agreed between a Member requesting transmission service and a Member willing to provide transmission service, each Member shall request interconnection or transmission service, which such Member has the right to obtain by order of FERC pursuant to Sections 210, 211 and 212 of the FPA, from another Member in accordance with these Bylaws in lieu of requesting such service by order of FERC pursuant to Sections 210, 211 and 212 of the FPA; provided however, this Section 5.11 shall not apply where the Member which is served a request for service pursuant to these Bylaws fails to comply with any of its duties or obligations under these Bylaws with respect to such request.

5.7 **Stranded Investment.** Except as otherwise provided in a transmission service contract or other separate contract, a Member shall be entitled to compensation for stranded investments only to the extent such stranded investments were made as a result of (i) a legal or regulatory requirement or (ii) contractual obligation on behalf of the Member whose request for transmission service or proposal to construct transmission facilities would cause such stranded investment. The Member owning such stranded investment shall be compensated by the Member causing such stranded investment for quantifiable costs associated with such stranded investment only to the extent and in a manner as permitted by then current FERC policy.

§ 6 Coordinated Planning; See Coordinated Transmission Planning Section

§ 7 Dispute Resolution; See Dispute Resolution Section

§ 8 Compliance with Section 212 of the FPA; See Retail Wheeling Section

9. RESELLING TRANSMISSION SERVICE:

Unless otherwise mutually agreed, a Member may assign any agreement for transmission service, including all terms and conditions contained therein, negotiated pursuant to a request for service made under these Bylaws to a third party, provided that the sale or assignment causes no adverse reliability impacts to the Transmitting Member or other affected entities, the capacity rights or contracted-for service are used only for wholesale transactions, and the Transmitting Member has the right of first refusal for a such assignment, which right must be exercised promptly.[2]

[2]EPAct '92 and these Bylaws provide transmission requesters with expanded rights to request and receive transmission service. Certain SWRTA participants are concerned that some players in the transmission market may utilize these rights to buy and sell transmission capacity at a profit. This section is intended solely to preclude Members from reaping undue profits by brokering service. It is not intended to prevent members from reselling service if their anticipated need for service does not develop.

5.4.9 Selection of Physical Means or Incremental Additions To Provide Transmission Service. The Transmission Provider shall, in its sole discretion, select the physical means (with respect to existing facilities) or Incremental Additions by which it provides transmission service to a Transmission Requester in accordance with these Bylaws, provided that the cost of such transmission service is no greater than the cost would have been had the lowest cost reasonable alternative been selected (e.g., the Transmission Provider may have selected a higher cost alternative in consideration of future expansion or other prudent purposes).

§ 5.5 Determination of Pricing and Other Terms and Conditions of Transmission Service; See Pricing Principles/Practices Section

5.6 Assignment of Transmission Services or Ownership-Like Rights.

5.6.1 Conditions of Assignment. Transmission service or Ownership-Like Rights shall be assignable or reassignable by an entity which has acquired Ownership-Like Rights or is receiving transmission service pursuant to a contract entered into in accordance with these Bylaws, provided that (i) written notice of the proposed assignment is provided to the Transmission Provider at least 90 days prior to the effective date of the proposed assignment, (ii) the Transmission Provider's system use to serve its Planned Native Load is not impaired or the continued reliability (based upon consistently applied reliability criteria and guidelines of the Transmission Provider, NERC and WSCC) of the Transmission Provider's electric system is not unreasonably impaired, (iii) the assignee agrees to accept and discharge all obligations associated with such assigned transmission service upon commercially reasonable terms and conditions approved by the Transmission Provider, which approval shall not be unreasonably withheld, and (iv) the assignee is a Member, or if no Member is willing to accept such assignment, the assignment may be made to any entity eligible to request or required to provide service under Section 211 of the FPA.

5.6.2 No Assignments for Retail Wheeling. No assignment shall impose involuntarily on any Transmission Provider, or any other Member affected by the assignment, any obligation to provide or cooperate in providing wheeling to an ultimate consumer except as permitted by FERC order consistent with Section 212(h) of the FPA.

5.6.3 No Profit from Assignment. No Transmission Requester or subsequent assignee shall assign any of its rights to transmission service obtained under these Bylaws for more than the cost of such transmission service rights to such Transmission Requester or assignee.

4. RIGHTS IN INCREMENTAL FACILITIES:

Unless otherwise mutually agreed or prohibited by law or regulation, a Requesting Member shall obtain ownership or Ownership-Like Rights in Incremental Facilities installed pursuant to the Requesting Member's transmission service request if the Transmitting Member requires the Requesting Member to pay for such Incremental Facilities through a capital contribution.

4.1 Unless otherwise mutually agreed, the Requesting Member shall obtain ownership if the Incremental Facilities (i) interconnect two (2) or more electrical control areas; or (ii) are identified as radial transmission lines pursuant to an agreement; or (iii) are functionally separated from the Transmitting Member's integrated network such that the Incremental Facilities are, or can be, operated and planned as a single facility; or (iv) interconnect a Requesting Member's generation resource with the Transmitting Member's system at a single point.

4.2 Unless otherwise mutually agreed, the Requesting Member shall obtain Ownership-Like Rights if the Incremental Facilities are part of a Transmitting Member's integrated network to such an extent that the Incremental Facilities cannot be operated and planned as a single facility.

§ 5 Pricing Principles; See Pricing Principles/Practices Section

10.8 Ownership and Ownership-Like Rights. If a Transmission Provider requests a Transmission User to advance the capital costs of Incremental Facilities and the Transmission User agrees to advance such costs, the Transmission User shall be afforded: (i) the option to own that portion of any Interconnection constructed with capital costs that are advanced or (ii) the option to enjoy Ownership-Like Rights in any Incremental Facilities, other than an Interconnection, constructed with capital costs that are advanced. In regard to an Interconnection, a Transmission User shall have the option of participating in the project by advancing the capital costs of Incremental Facilities required to provide requested transmission services and to have ownership of a prorata share of such facilities, regardless of whether the Transmission Provider requests such an advance.

such Incremental Additions is needed pursuant to such Long Term Transmission Plan consistent with the Planned Native Load requirements, or such other date as mutually agreed to by the Transmission Provider and the Transmission Requester; provided that the Transmission Requester pays the costs associated with the acceleration of the construction of the Incremental Additions through rates or advances of PFC or CIAC (consistent with Sections 5.4.2, 5.4.3 and 5.5) sufficient for the accelerated acquisition and construction of the Incremental Additions.

To the extent permitted by then-current FERC policies, if PFC or CIAC is advanced by a Transmission Requester which acquires ownership or Ownership-Like Rights in accordance with Sections 5.4.2 or 5.4.3, respectively, then the Transmission Provider shall repay to the Transmission Requester a proportionate amount of its PFC or CIAC and, simultaneously, the Transmission Requester shall transfer its ownership or Ownership-Like rights, respectively, to the Transmission Provider at such time as the Incremental Additions are required by the Transmission Provider pursuant to its Long Term Transmission Plan consistent with its Planned Native Load requirements, or such other date as mutually agreed to by the Transmission Provider and the Transmission Requester. Notwithstanding the temporary use of such Incremental Additions to provide transmission service to such Transmission Requester, the Transmission Provider shall continue to be obligated to build Incremental Additions to meet the transmission request of such Transmission Requester without interruption of transmission service, subject to all the terms and conditions of this Section 5 and the applicable Appendix A.

5.4.6 Commercially Reasonable Assurances Regarding Payment of Costs Incurred for Incremental Additions. A Transmission Requester shall provide to the Transmission Provider commercially reasonable assurances regarding the payment of construction costs incurred by a Transmission Provider with respect to the planning, licensing, design, acquisition and construction of Incremental Additions.

5.4.7 Costs of Incremental Additions Reduced by Amount of Benefits to Transmission Provider's Electrical System. The costs of Incremental Additions paid by a Transmission Requester shall be reduced by the amount of legitimate, verifiable and economic benefits to the transmission system of the electrical system providing the transmission service.

5.4.8 Operation and Maintenance of Incremental Additions. Incremental Additions on a Transmission Provider's system, including Radial Transmission Facilities, shall be operated and maintained by such Transmission Provider.

5.4.4 Service Associated with CIAC-Financed Incremental Additions Which Are Not Radial Transmission Facilities.

5.4.4.1 Ownership-Like Rights acquired by the Transmission Requester for the requested amount of transmission services made possible by CIAC-financed Incremental Additions which are not Radial Transmission Facilities shall result in the Transmission Provider making the requested amount of transmission services available to the Transmission Requester for as long as such Transmission Requester pays for (i) the operation, maintenance and replacement costs of such Incremental Additions, (ii) any increased operation or maintenance costs on the Transmission Provider's system which are a direct result of the operation of such Incremental Additions, and (iii) other charges, if any, which are consistent with the FPA and FERC regulations, policies and precedents under similar circumstances.

5.4.4.2 In addition to other terms and conditions regarding transmission service provided with respect to Incremental Additions which are not Radial Transmission Facilities and are financed through CIAC by a Transmission Requester, the transmission service contract shall specify the amount, and terms and conditions, of transmission service to be provided by the Transmission Provider. Except as otherwise agreed to by the Transmission Provider and the Transmission Requester, there shall be no adjustment in such specified amount of Firm Transmission Service in the event an increase or decrease in the rating of such Incremental Additions or the resulting transfer capability occurs during the period in which service is to be provided to such Transmission Requester in connection with such Incremental Additions; i.e., the risks of a downrating and the benefits of an uprating of the Incremental Facilities or the resulting transfer capability shall remain with the Transmission Provider.

5.4.5 Incremental Additions in Transmission Plans. If the construction of the Incremental Additions included in the Transmission Provider's Long Term Transmission Plan consistent with the Planned Native Load requirements, is accelerated in order to provide transmission service requested in accordance with Section 5 and the applicable Appendix A, the transmission service shall be provided to a Transmission Requester pursuant to a separate contract developed in accordance with these Bylaws. Such transmission service shall be provided to the Transmission Requester until such time as the capacity of

Transmission Provider's electrical system. Furthermore, the Transmission Provider shall, at the request and sole cost of the Transmission Requester, support before any Regulatory Authority the Transmission Requester's efforts to construct, acquire and finance Radial Transmission Facilities which are intended to be interconnected with the Transmission Provider's electrical system. Nothing in this Section 5.4.1 shall require the Transmission Provider to interconnect such Radial Transmission Facilities. Notwithstanding the provisions of Section 5.4.8, the Transmission Requester shall be responsible for the operation and maintenance of Radial Transmission Facilities constructed by a Transmission Requester.

5.4.2 Financing Incremental Additions - Radial Transmission Facilities. If, in accordance with the applicable Appendix A and this Section 5, a transmission service request will require the acquisition and construction of Incremental Additions which are Radial Transmission Facilities, the Transmission Provider shall determine, in its sole discretion, whether such Incremental Additions shall be financed (i) by the Transmission Provider, or (ii) utilizing PFC from the Transmission Requester. Except as otherwise mutually agreed to, ownership rights to such Incremental Additions shall be acquired by (i) the Transmission Provider if it finances such Incremental Additions, or (ii) the Transmission Requester if PFC from the Transmission Requester is utilized to finance such Incremental Additions.

5.4.3 Financing Incremental Additions - Not Radial Transmission Facilities. If, in accordance with the applicable Appendix A and this Section 5, a transmission service request will require the acquisition and construction of Incremental Additions which are not Radial Transmission Facilities, the Transmission Provider shall determine, in its sole discretion, whether such Incremental Additions shall be financed (i) by the Transmission Provider, or (ii) utilizing CIAC from the Transmission Requester. The Transmission Provider shall own such Incremental Additions regardless of the financing method utilized for such Incremental Additions; provided however, if the Transmission Provider determines to finance such Incremental Additions utilizing CIAC from the Transmission Requester, the Transmission Requester shall acquire Ownership-Like Rights for the requested amount of transmission services as provided in Section 5.4.4.

provide notice of the project to all Members through posting in the Association newsletter or electronic bulletin board.

§ 10.6 Requests Involving Only Members of Subregional Coordination Groups; See Reciprocal Agreements

§ 10.7 Tax Exempt Financing; See Tax Exempt Financing Section

5.4 Transmission Service Requiring Incremental Additions.

5.4.1 Transmission Provider Obligation to Acquire and Construct Incremental Additions. If following the process of requesting transmission service in accordance with the applicable Appendix A and this Section 5, it is determined that Incremental Additions will be required to provide the requested transmission service, the Transmission Provider shall be obligated to acquire and construct Incremental Additions to provide such transmission service, subject to obtaining all necessary approvals or property rights under applicable Federal, state and local laws. The Transmission Requester shall fully support at its expense the need for such Incremental Additions before any court, Regulatory Authority or governing body which is empowered to grant any such property right, permit or approval.

The Transmission Provider shall not be obligated to construct Incremental Additions if (i) after making good faith efforts to obtain the necessary approvals or property rights under applicable Federal, state and local laws, the Transmission Provider has been unable to secure those approvals; or (ii) the Transmission Provider is prohibited by legislative, judicial or Regulatory Authority action for any reason from recovering in its rates its projected, reasonable investment in the Incremental Additions, as well as a return on that investment to the same extent, and within the same period of time (or shorter period of time if the requested service is for a shorter period of time than the normal depreciation life), as it is entitled under the law to recover a return of, and a return on, its investment in facilities constructed by it to serve its native load or core customers. If the Transmission Provider's obligation to construct Incremental Additions is discharged by reason of a legal prohibition on recovery of its reasonable projected investment in Incremental Facilities, as identified in subdivision (ii) of this subparagraph, it shall nevertheless construct the Incremental Additions if (a) acting in its sole discretion, the Transmission Provider elects to do so, or (b) the Transmission Requester provides CIAC or PFC in an amount sufficient to finance the costs of constructing the Incremental Additions and the Transmission Provider obtains all necessary approval and property rights for the construction under applicable Federal, state or local law.

In the event the Transmission Provider's obligation to acquire and construct Incremental Additions is discharged pursuant to the immediately preceding paragraph, the Transmission Provider shall take no action which opposes or impedes the Transmission Requester's efforts to construct, acquire and finance Radial Transmission Facilities which are intended to be interconnected with the

3.3.7 If the study results demonstrate a need for and the feasibility of building new facilities or providing an interconnection, interested Members may elect to pursue the project, or, absent such interest in a multi-party project, the Requesting Member may elect to pursue the project. The Transmitting Member must make good faith efforts to build the project based upon the conditions outlined in the report issued pursuant to Sections 3.3.3 or 3.3.4 hereof and an agreement negotiated among participating Members. The Transmitting and Requesting Members shall provide notice of the potential project to all Members through the Planning Committee.

3.4 Request and Response Log

By the most economic means available, including, but not limited to, an electronic bulletin board, Members shall collect and disseminate or cause to be made available a log of Members' requests for transmission service and the responses thereto provided pursuant to these Bylaws.

10.5 Requests Requiring Upgrades, Additional Facilities or Interconnections.

10.5.1 If the Transmission Provider's report issued at the completion of a study performed pursuant to Subsection 10.4 concludes that the Transmission Provider does not have sufficient Available Transmission Capacity to provide the requested service initially or for the term of the request, it shall include at a minimum: (i) a detailed description of the required Incremental Facilities, (ii) the estimated cost of and cash flow requirements for installing the necessary facilities or providing the interconnection; (iii) the estimated time necessary to build such facilities or provide such interconnection, including the estimated time required for environmental studies, licensing and regulatory approvals, (iv) the estimated incremental capacity added to the transmission system by the additional facilities, (v) whether the Transmission User will be requested to advance capital in connection with installing the necessary facilities.

10.5.2 If the study results demonstrate a need for a transmission interconnection with another entity, the Transmission Provider shall make a good faith effort to arrange a joint study with the other entity to evaluate the impact of such an interconnection. Costs for this additional study shall also be borne by the Transmission User.

10.5.3 If the study results demonstrate a need for and the feasibility of building new facilities or providing an interconnection and the Transmission User elects to proceed with its request for transmission services, the Transmission Provider shall be obligated to either build the project or cause the project to be built and provide the requested service based upon the conditions outlined in the Transmission Provider's report, provided such conditions are not under dispute and an agreement has been negotiated between the Transmission Provider and the Transmission User, subject only to federal, state and provincial law, the FPA and FERC's standards and policies. The Transmission Provider shall

transmission facilities or are new facilities; (iv) the estimated time necessary to build such facilities or provide such interconnection, including the estimated time required for licensing and regulatory approvals; and (v) the estimated incremental capacity added to the transmission system by the additional facilities.

3.3.6 If the results of the study undertaken pursuant to Sections 3.3.3 or 3.3.4 hereof demonstrate a need for a transmission interconnection with another Member, the SWRTA Members participating in the multi-party study, or absent such multi-party study, the applicable Transmitting and Requesting Members shall arrange a study with the other Member to determine the requirements for an interconnection. If the other entity is not a SWRTA Member, the Members participating in the multi-party study, or absent such multi-party study, the applicable Transmitting and Requesting Members shall make a good faith effort to arrange such a study. Costs for this additional study shall be allocated among the SWRTA Members participating in and benefiting from the multi-party study, or absent such a multi-party study, shall be borne by the Requesting Member.

wishes to pursue the request further, the Requesting Member (i) may invoke the dispute resolution procedures of Section 7 hereof, or (2) shall solicit in writing expressions of interest from other SWRTA Members for participation in a multi-party study to determine what upgrades, additional transmission facilities, or additional interconnections are required or may be desired to accommodate the requested service and other interests. Interested Members must respond to the solicitation with a letter of interest within the time period specified in the solicitation. Members electing to participate in the multi-party study shall negotiate and enter into a study agreement containing, at a minimum, the study scope, assumptions, criteria, timetable, estimated costs and allocation of costs. Unless otherwise mutually agreed, the Transmitting Member to which the original request for service was made shall conduct the study.

3.3.4 If no other SWRTA Members elect to participate in the additional study, the Requesting Member may, at its sole expense, require the Transmitting Member to conduct the additional study pursuant to a study agreement negotiated between the Requesting and Transmitting Members. The Transmitting Member shall be responsible for conducting this additional study with participation and input from the Requesting Member, or as otherwise agreed to in the study agreement, and a copy of the study results shall be made available to the Requesting Member and the Planning Committee.

3.3.5 The report issued at the completion of any study undertaken pursuant to Sections 3.3.3 or 3.3.4 hereof shall include, at a minimum (i) the estimated cost of and cash flow requirements for installing the necessary facilities or providing the additional interconnection; (ii) whether the Transmitting Member elects to provide financing for the additional facilities or interconnection; (iii) whether the necessary facilities are an upgrade of existing

Provider's proposed price, terms and conditions for the requested service. If the Transmission User does not agree to the proposed contract, the Transmission Provider and the Transmission User shall proceed in accordance with Section 12 of this Governing Agreement. If the Transmission Provider and the Transmission user agree upon a contract for service, the Transmission Provider shall promptly take all other actions reasonably necessary to effectuate service.

5.2.2 Commitments by Non-Transmission-Owner Members. Where Member B does not own the transmission system that would be used for the specific planned service, the commitment required by Section 5.2.1 shall consist of a contract for transmission service (including Ownership-Like Rights or ownership rights, as the case may be) in accordance with these Bylaws between Member B and the Member which owns the subject transmission system. Member B shall submit a request pursuant to Section 5 and the applicable Appendix A for such contract no later than 30 days following the submittal of the competing request. The contract between the Member B and the owner of the subject transmission system shall be executed no later than 180 days (or such longer period of time as agreed to by Member B) from the date of the competing request.

5.3 **Transmission Service Using Available Transmission Capacity.** A Transmission Provider shall offer transmission service utilizing Available Transmission Capacity to any Transmission Requester in accordance with this Section 5 and the applicable Appendix A. The position of any Member that transmission capacity is not available as a result of the application of the provisions of Sections 3.2(i) through 3.2(v) may be challenged by any other Member and fully reviewed in any Dispute Resolution Proceeding. Forecasts of service area demand adopted by each Member following a public hearing by a state's energy planning agency or other public process (as may be adjusted within the Zone of Reasonableness established by the Planning Committee pursuant to Section 9) shall be utilized for purposes of determining Planned Native Load and shall be Consistently Applied. If, following the process of requesting transmission service in accordance with the applicable Appendix A and this Section 5, transmission service is to be provided using Available Transmission Capacity, rates and other terms and conditions of such transmission service shall be determined and memorialized in a separate contract in accordance with Section 5.5 through Section 5.12.

3.3 Response to Request for Service

3.3.1 The Transmitting Member shall respond to a request for transmission service from a Requesting Member in a manner consistent with Sections 212 and 213 of the FPA and FERC's then-current policy regarding such response.

3.3.2 The Transmitting Member shall provide the requested transmission service if it has sufficient Available Transmission Capacity on its Existing Facilities, or shall conduct an initial study at the Requesting Member's expense to determine whether it has sufficient Available Transmission Capacity to provide the requested service initially and for the full term of the request. The Transmitting Member's reasonable study costs shall be billed to and paid by the Requesting Member in advance. Any reconciliation for over or underpayment shall be done upon completion of the initial study work. Such initial study shall be completed within a reasonable period in accordance with FERC's then-current policies and as agreed to by the Transmitting Member and Requesting Member. If such Members cannot agree on the time period for the initial study, the Planning Committee shall designate the period, which determination shall be final and not subject to the dispute resolution procedures of Section 7 hereof. The Transmitting Member shall be responsible for conducting the initial study with participation and input from the Requesting Member, as mutually agreed to, and the results of the initial study shall be made available to the Requesting Member and the Planning Committee.

3.3.3 If the Transmitting Member's report issued at the completion of an initial study performed pursuant to Subsection 3.3.2 shows that the Transmitting Member does not have sufficient Available Transmission Capacity on Existing Facilities or lacks an existing interconnection necessary to provide the requested service initially or for the term of the request, and if the Requesting Member

10.4 Response to Request for Firm Transmission Service.

10.4.1 The Transmission Provider shall respond to a request for transmission service from a Transmission User in a manner consistent with Section 212 of the FPA and FERC's then current policies (as presently embodied in its "Policy Statement Regarding Good Faith Requests for Transmission Services").

10.4.2 The Transmission Provider may elect to provide the requested transmission service without further study, or to conduct a study, if such is reasonably required, at the Transmission User's expense, to determine: (i) whether it has sufficient Available Transmission Capacity to provide the requested service initially and for the full term of the request, or (ii) what upgrades, additional transmission facilities or interconnections are required to accommodate the requested service. The Transmission Provider's reasonable study costs shall be billed to and paid by the Transmission User in advance based upon the Transmission User's reasonable estimate of such costs. Any reconciliation for over or underpayment shall be done upon completion of the study work. Such study shall be completed within a reasonable time period in accordance with the FERC's then-current policies, as agreed to by the Transmission Provider and Transmission User or, if such Members cannot agree, as determined by the Planning Committee. The Transmission Provider shall be responsible for conducting the study with participation and input from the Transmission User, as mutually agreed to, and the results of the study shall be made available to the Transmission User, the Planning Committee, and any other Member requesting it.

10.4.3 Subject to the requirements of the National Environmental Policy Act or other environmental laws, if a Transmission Provider is able to provide transmission service without further study or if the study demonstrates that the requested service can be provided using Existing Facilities, the Transmission Provider shall promptly offer a contract to the Transmission User which shall include the Transmission

TRANSMISSION SERVICE

WATSCO

5. TRANSMISSION SERVICE BETWEEN WATSCO MEMBERS:

5.1 Members Obligated to Provide Transmission and Interconnection Services. Unless otherwise agreed between or among affected Members with respect to a request for interconnection and/or transmission service, it is the intent of these Bylaws that interconnection and transmission services which Members are obligated to provide, and Members' obligations to construct Incremental Additions under these Bylaws, be equivalent to that required by the FPA and FERC regulations, policies and precedents.

5.2 Request for Transmission Service. A Transmission Requester shall request interconnection or transmission service from a Transmission Provider in writing (identified as a "WATSCO" request) and as provided in this Section 5, the Appendix A which coincides with the principal office of the Transmission Provider and, to the extent not otherwise provided therein, in a form established by the Planning Committee. Such form of request shall be in accordance with the requirements of the final FERC Policy Statement Regarding Good Faith Requests as determined in Docket No. PL93-3-000, as such requirements may be amended or supplemented from time to time by the FPA or FERC regulations, policies or precedents, and shall contain such additional information approved by the Board of Directors. The submittal of such a transmission request initiates the process of evaluating the request, conducting the necessary studies by the Transmission Provider, and ultimately providing the requested service pursuant to a contract entered into in accordance with the provisions of these Bylaws. This process is set forth in this Section 5 and the applicable Appendix A hereto, "Transmission Service Requests." An Appendix A shall be prepared and attached to these Bylaws with respect to each State in which a Member is located.

5.2.1 Transmission Requests Which Conflict With Planned Transmission Service. Subject to a Member's right to challenge a Transmission Provider's determination of Available Transmission Capacity in accordance with Section 5.3, no Transmission Provider shall be required to provide transmission service utilizing existing facilities to satisfy a request pursuant to this Section 5 and the applicable Appendix A which competes with or adversely affects the Transmission Provider's planned use of its transmission facilities to satisfy its Planned Native Load. However, whenever a Member ("Member A") submits a request to a Transmission Provider for transmission service pursuant to this Section 5 and the applicable Appendix A which competes with or is adversely affected by another Member's ("Member B") specific planned need for transmission services from the Transmission Provider set forth in Member B's transmission plan pursuant to Section 4.7, Member B shall have the first right to Member B's planned service to the extent that Member B subsequently commits to such specific service in a contract in accordance with Section 5.2.2. No Member shall have any responsibility with respect to any other Member regarding such Member's specific planned need for transmission services set forth in its transmission plan except to the extent required under a contract or regulatory obligation to provide transmission services.

SWRTA

3. REQUESTS FOR TRANSMISSION SERVICE:

3.1 Service to be Provided

Each Transmitting Member shall provide transmission service from its Available Transmission Capacity on its Existing Facilities, and/or from Incremental Facilities where necessary, to any Requesting Member on a basis consistent with the FPA, FERC's applicable standards and policies, and the principles set forth in these Bylaws, and as detailed in an agreement negotiated between such Members. Members not subject to Sections 211, 212 and 213 of the FPA shall provide transmission service on the same basis as those Members which are subject to Sections 211, 212 and 213 of the FPA.

3.2 Request for Service

A Requesting Member desirous of obtaining transmission service from a Transmitting Member shall pursue its request for such service pursuant to these Bylaws in lieu of exercising its procedural rights pursuant to Section 211 of the FPA. In making a good faith request for transmission service, a Requesting Member shall provide information in writing to the Transmitting Member regarding its request for transmission service consistent with Section 211 of the FPA and FERC's then-current policy regarding such requests.

WRTA

10. REQUESTS FOR TRANSMISSION SERVICE.

10.1 Service to be Provided. Subject to the provisions of Section 14, each Transmission Provider shall provide transmission service from its Available Transmission Capacity on its Existing Facilities, or from Incremental Facilities where necessary, to any Transmission User on a basis consistent with the FPA, FERC's then-applicable standards and policies and this Governing Agreement. Such service shall be provided on the basis detailed in the Transmission Provider's applicable tariff, or an agreement negotiated between the Transmission Provider and the Transmission User or established by an Award, if such tariff does not exist. Members not subject to Section 211 of the Federal Power Act agree to provide transmission service on the same basis as those Members that are subject to such requirements.

10.2 Tariff or Agreement Required. Transmission service shall be provided solely under a separate tariff or agreement and this Governing Agreement shall not, in and of itself, be construed to be a tariff or service agreement providing for transmission service.

10.3 Request for Service. Each Transmission User desirous of transmission services from a Transmission Provider shall, in each instance, pursue its request for such service pursuant to the procedures set forth in this Governing Agreement in lieu of exercising its procedural rights pursuant to Section 211 of the FPA. A Transmission User requesting transmission service shall provide to the Transmission Provider information regarding its request for transmission service, consistent with either the FERC's then-current policy regarding such request (as currently embodied in its "Policy Statement Regarding Good Faith Requests for Transmission Services") or a FERC-approved tariff of the Transmission Provider under which transmission service is sought. A request for transmission service made consistent with this subsection shall be deemed by Members to be a "good faith request" for transmission service within the meaning of Section 213 of the FPA.

TRANSMISSION SERVICE

INTERFACE WITH WSCC

WATSCO

4.9 **Avoid Duplication of Planning Activities; Trial Period With WSCC.** Certain of the planning and data collection activities which are provided for in these Bylaws, or which may be undertaken by the Planning Committee, may be activities performed by the WSCC. To the extent feasible and economical, it is desirable to avoid duplication of effort between WSCC and WATSCO.

4.9.1 WSCC Executive Committee Recommendation; WSCC Undertakes Planning Activities. If the Executive Committee of WSCC recommends or supports, in writing:

(i) altering the WSCC Executive Committee governance structure to permit an equal number of seats on the Executive Committee among transmitting utilities, transmission dependent utilities, and non-utility generators;

(ii) determining matters before the Executive Committee by a simple majority vote of its members; and

(iii) allowing each member of WSCC to designate its agent for participation in WSCC activities without the requirement that the agent be an employee of the member;

then the Board of Directors (or its designee(s)) shall, unless determined otherwise by a 2/3 majority vote of the Directors of each category of membership currently holding office, seek satisfactory arrangements (including a contract, if necessary) with the WSCC to undertake and carry out, as an agent of WATSCO, or its Members, those planning and data collection activities required under these Bylaws or authorized by the Planning Committee that are performed by the WSCC. Except as provided in Section 4.9.2, the arrangement for WSCC to perform such planning and data collection activities shall terminate on November 15, 1994.

4.9.2 Adoption of Executive Committee Recommendations; WSCC Continues Planning Activities. Unless determined otherwise by a 2/3 majority vote of the Directors of each category of membership currently holding office, if the WSCC Executive Committee adopts by November 15, 1994 the substance of the proposals as set forth in Sections 4.9.1(i), (ii) and (iii), the WSCC shall perform those planning and data collection activities required under these Bylaws or authorized by the Planning Committee that are performed by the WSCC for a period of two years beginning from the date of such adoption (the "Trial Period"), subject to satisfactory arrangements (including a contract, if necessary) between WATSCO and WSCC.

4.9.3 Board Determination Regarding Continued Arrangements with WSCC. At the end of the Trial Period, the Board of Directors may (i) continue similar arrangements with the WSCC or (ii) determine to enter into other arrangements with the WSCC, by a 2/3 majority vote of the Directors of each category of membership currently holding office. If no such arrangement with WSCC is sought or reached, the Board shall determine how planning and data collections under these Bylaws shall be accomplished.

SWRTA

6.6 Interface with WSCC

In order to avoid unnecessary duplication, Members may utilize WSCC reports to the maximum extent possible to fulfill the information reporting requirements set forth in Section 6.3 hereof. Typical reports currently produced by WSCC include: (i) notification procedures in compliance with the Changes in Facility Ratings and/or Operating Procedures; (ii) formal and informal Progress Reports; (iii) Significant Additions and Changes to System Facilities Report; and (iv) Loads and Resources Report. Members shall expand these reports to include all Interconnected Transmission System projects or any project that impacts any other Member over the ten (10) year planning horizon and shall file them on an annual basis with the Planning Committee. The Planning Committee shall develop standard forms and other tools which Members may use to fulfill reporting requirements for both WSCC and SWRTA. For WSCC data, the WSCC Data Release Guidelines shall be followed by all Members.

WRTA

9.6 Duplication of Planning Activities. The Association shall seek to avoid duplication of planning effort in the Western Interconnection whenever possible. To this end, the Association may contract with WSCC to provide planning services to meet the needs of the Association for coordination of transmission and data collection. In such event, the Planning Committee shall function as a policy group to give direction to the Board regarding the planning needs of the Association, provide liaison with WSCC Committees for Members who are not members of WSCC, and evaluate the adequacy of services provided through WSCC for consideration by the Board.

See WRTA § 12.2.3

See WRTA § 17

INTERFACE WITH WSCC

TABLE 1

PLANNING OBLIGATIONS

	Textual Description	Quantitative/ Technical Description	Power Flow Data	Plots, Maps Diagrams
LTTP OBLIGATIONS				
Planned Facilities				
subs, lines, transformers, gen, devices, etc	X	X	X	
- ratings	X	X	X	
- single line diagrams				X
- impedance diagrams				X
- bus and bus arrangements				X
- estimated costs	X	X		
System Adequacy				
criteria	X	X		
western performance assessment	X			
System Use (Existing and Planned)				
imports	X	X		
exports	X	X		
contractual commitments	X	X		
prudent reserve	X	X		
Short Term Firm (required for reliability)	X	X		
Available Transmission Capacity	X	X		
DATA REQUIREMENTS & OBLIGATIONS				
Existing System Facilities/Ratings				
transmission lines		X	X	
generation units		X	X	
- operational		X	X	
- standby reserve		X	X	
- availability status		X		
transformers		X	X	
reactors (line and bus/tv)		X	X	
capacitors (series and shunt		X	X	
power electronic devices		X	X	
synchronous condensers		X	X	
system single line diagram				X
system impedance diagram				X
bus and bus arrangements				X
system map				X
Base Case Power Flows & Stability				
as determined by the WSCC	X		X	X
Load Characterization				
weather normalization methodology	X			
summer rate and base(peak load)	X	X		
peak/light MW rate by sub		X		
peak/light MVAR rate by sub		X		
load composition		X		
Remedial Action Scheme				
description	X			
arming limits	X	X		
triggering events	X	X		
logic diagram				X
actions initiated	X	X		
System Limits Not Readily Apparent In Power Flows				
high/low voltage limits	X	X		
non-transducered equipment (CBs, PTs, etc.)	X	X		
post & simultaneous intact limits	X	X		
thermal or stability related limitations	X	X		
post transient voltage limitations	X	X		
other constraints	X	X		
Short-Circuit Duty Information				
expected yearly duties at each sub	X	X		
equipment ratings (continuous and interrupting)		X		

Textual and/or qualitative descriptions of RAS shall include information regarding the need for the scheme, the triggering events, logic diagrams, how the scheme is armed, and the actions to be initiated by the scheme.

System Limits Not Readily Apparent in Power Flows

There are system constraints that cannot be readily deduced from power flow case outputs (e.g., simultaneous or non-simultaneous import or export limits on interties). All such system constraints shall be described in the LTTP. Such constraints may include equipment limitations (e.g., circuit breaker ratings, etc.).

Textual descriptions of system limits not readily apparent from power flow case output shall include an explanation of the nature of the limit (voltage limited, thermally limited, etc.), the conditions under which the limit occurs, if necessary to discern the system limitation (such as peak loads, heavy imports, or post-transient conditions), and other information necessary to enable a general understanding of the limits and how the limits might affect an analysis of the capabilities of the power system.

Quantitative descriptions shall include a listing of the normal and emergency ratings of the non-represented limiting equipment by substation (e.g., the smallest circuit breaker in a substation).

Short-Circuit Duty Information

For purposes of this Exhibit A, "short-circuit duty information" means projected short-circuit duty levels and equipment ratings at each substation. Such information shall be sufficient to assess the adequacy of substation equipment, as well as determine the effects of increased short-circuit duties from proposed new generation or transmission projects or line rearrangements.

Textual descriptions of short-circuit duty information shall include an explanation of the methodology and assumptions used to derive short-circuit duties.

Qualitative descriptions of short-circuit duty information shall include a listing by substation of the short-circuit duty calculated under a three-phase grounded fault condition. In addition, the continuous and current rating and interrupting rating of the limiting circuit breaker in the substation shall be included in such information.

Each Member shall include in its LTTP sufficient data to permit modeling of its existing system facilities to allow other Members to be able to predict system performance under varying conditions that may arise from new transmission services, new transmission or generation projects or other changes to the system that were not originally contemplated by the such Member.

Technical descriptions shall contain sufficient information to understand how facilities are represented in the power flow data set where equivalent electrical representation of groups of generators, lines, transformers or other equipment are used for the sake of computing expediency. Quantitative descriptions shall also include sufficient data to permit other Members to determine the equivalents used and to conduct technical analyses with a sufficient degree of accuracy to gain a general understanding of the system performance under various load or contingency conditions. Where equivalents are used, individual generators, transformers, lines, (and/or line segments), capacitor banks, reactors and other devices shall be described individually.

Technical descriptions shall also include normal and emergency ratings for the limiting circuit breaker in each substation. Although this is not typically modelled in a powerflow, this information is necessary to gain an understanding of possible constraints.

Base Case Power Flows and Stability

Each Member shall include in its LTTP the information required for power flow and stability data base reports as periodically requested by WSCC. WSCC usually maintains a ten-year data base containing four seasonal and two loading conditions per year. Each year, WSCC updates 11 cases.

Load Characteristics

For purposes of this Exhibit A, "load characteristics" means information describing how substation loads can be represented in power flow and stability cases. Such information shall be sufficiently detailed to be able to develop other seasonal or time-of-day load conditions.

Textual descriptions of load characteristics shall contain a description of weather normalization methodologies used for the Member's loads and the watt/var ratio basis of the Member's loads. The description of weather normalization for loads shall also describe how the Member treats unusual weather conditions in forecasting future loads. The textual description of the Member's watt/var ratio basis should explain its assumption of var loads.

The quantitative description of load characteristics shall include a listing of each substation's watt/var ratio, the peak/light MW ratio, the peak/light MVAR ratio and the load representation for dynamic modelling (constant current, constant impedance, etc.).

Remedial Action Schemes

For purposes of this Exhibit A, "RAS" means automatic schemes designed to operate in response to specific triggering events. These triggering events include, but are not limited to, low voltages, low frequencies, and loss of transmission lines or loss of generating units.

System Adequacy

For purposes of this Exhibit A, "system adequacy" means the performance of a Member's transmission system as measured against applicable planning criteria.

The textual description of system adequacy shall set forth the Member's transmission planning criteria and an assessment of the performance of the Member's system against the requirements of its planning criteria.

System Use

For purposes of this Exhibit A, "system use" means a description of the existing and future uses of a Member's transmission entitlements (through ownership, contract or other arrangements). A Member planning to obtain transmission service over another Member's transmission entitlements shall report such plans under system use. Such a reported planned use shall not constitute a request for service under the Bylaws

Quantitative description of system use includes a new use, extension of an existing use, or foregoing a previously declared intention to use transmission entitlements. Quantitative description of system use also includes, but is not limited to, use of transmission entitlements for imports, exports, contractual commitments, prudent reserve (which includes emergency capacity), short-term firm service (required for reliability) and other information which is necessary in order to determine Available Transmission Capacity in accordance with Section 3.2.

Quantitative descriptions of system use shall include a description of the Member's entitlements and other rights over facilities that are not owned by the Member. Members located within another Member's control area shall provide data regarding their existing and planned system use so as to permit the determination of Available Transmission Capacity in accordance with Section 3.2.

Quantitative descriptions of system use shall include data regarding the existing and planned system use on a year-by-year basis in a form as determined by the Planning Committee.

DATA AND ASSUMPTIONS OF A LONG TERM TRANSMISSION PLAN

An LTTP shall include supporting data and assumptions regarding existing system facilities, base case power flows, load characteristics, RAS, system limits not readily apparent in power flows and short circuit duty information.

Existing System Facilities

For purposes of this Exhibit A, "existing electrical system facilities" means the electrical facilities that are owned and operated by the Member as of the first year of the reporting period of an LTTP. Existing system facilities include all equipment designed to operate at 100 kV and above, with the exception of transformers with low-side voltage ratings below 100 kV. Existing system facilities also include, but are not limited to, transmission lines (ac & dc), generating units, transformers, reactors, capacitors, power electronic devices, synchronous condensers, circuit breakers, RAS, current transformers, potential transformers, etc., to the extent that such facilities limit or adversely affect the transfer capabilities of the transmission system.

EXHIBIT A

ADDITIONAL ELEMENTS OF A LONG TERM TRANSMISSION PLAN

Introduction

In addition to the requirements set forth in Sections 4.7 and 4.8 regarding a Long Term Transmission Plan (an "LTTP"), each Member shall prepare an LTTP consisting of the applicable information shown in Table 1 and described in this Exhibit A. The narrative description in this Exhibit A is intended to provide general information on the expected content and form of the information identified in Table 1, attached hereto and incorporated herewith.

Table 1 lists certain data and information which is required regarding existing systems and planned additions to the existing system. An "X" in the column under the heading "textual description", "quantitative description", "power flow data", or "plots, maps and diagrams" indicates the type of filing which is required. Additional descriptions of the information to be contained in the LTTP, including related data, is contained in the narrative portion of this Exhibit A.

The LTTP reporting requirements are for a ten-year period. The first year of such ten-year period shall be the first calendar year immediately following the year in which a biennial planning cycle begins as specified by the Planning Committee.

With respect to Planned Facilities, System Adequacy and System Use, each Member shall report all the required information for the first year of the required ten-year period in its LTTP. Only changes to the first-year information need to be reported for the remaining nine years of the LTTP, and the time at which they would occur.

Each Member shall undertake, in accordance with its normal transmission practices and Prudent Utility Practice, studies to identify constraints or limits to its system; however, any constraints or limits to its system identified in an LTTP shall not prohibit any Member from identifying additional constraints or limits which become known following the preparation of the most recent LTTP.

Planned Facilities

For purposes of this Exhibit A, "planned facilities" means all planned electrical facilities with operating ratings above 100 kV except transformers with low-side voltages below 100 kV. Planned facilities shall also include, but are not limited to, new transmission lines (ac & dc), generating units, transformers, reactors, capacitors, power electronic devices, synchronous condensers, circuit breakers, remedial actions schemes (RAS), current transformers, potential transformers, etc., but only to the extent that such facilities limit or adversely affect the transfer capabilities of the transmission system.

Textual descriptions of planned facilities shall include a description of the type, size, location and nature of the planned facilities, including estimated costs, the basis for the cost estimate, and the reasons for the planned facilities.

Technical descriptions, power flow data, and plots, maps and diagrams regarding planned facilities shall be consistent (i.e., similar in form and content so that it is it may be easily incorporated) with information required for existing system facilities and ratings described in this Exhibit A, and shall include other pertinent information that a transmission planning engineer would reasonably need to evaluate the planned facilities.

4.8.1 Transmission Needs - Each such Member shall provide to the Planning Committee assumptions and data as described in Section 4.8.2 and Exhibit A on such Member's need for transmission capacity over the period of time specified in the Exhibit A regarding Long Term Transmission Plans applicable to such Member, including any plans for additional resources or new and upgraded transmission facilities.

4.8.2 Assumptions and Data - Each such Member shall provide to the Planning Committee a detailed description of any underlying assumptions, criteria, supporting data and any other information required to be used in preparation of its Long Term Transmission Plan. Such assumptions, criteria and data shall include the assumptions, criteria and data in Exhibit A and as set forth below:

(i) Existing and planned control area generation to meet the needs of Planned Native Load;

(ii) Intertie ratings;

(iii) Explanation of how the information in (i) and (ii) above were developed as may be requested or determined by the Planning Committee; and

(iii) Any information required to be furnished in compliance with FERC regulations with respect to Section 213 of the FPA.

4.8.3 Additional Information. The Planning Committee may require Members to provide any additional information at times and in a form deemed necessary by the Planning Committee to accomplish the goals of coordinated transmission planning.

.8.4 Draft Long Term Transmission Plan - Each such Member shall prepare a draft Long Term Transmission Plan to serve all its forecasted transmission needs over the period of time specified in Exhibit A regarding Long Term Transmission Plans applicable to such Member.

4.8.5 Review and Comment - The Planning Committee shall make available to each Member all Long Term Transmission Plans for review and comment.

4.8.6 Final Long Term Transmission Plan - Each such Member shall prepare and provide to the Planning Committee a final Long Term Transmission Plan which takes into consideration the comments received.

4.8.7 Cooperation - Each Member shall cooperate with the Planning Committee in preparing the plans pursuant to this Section 4.8.

4.10 **Notice of Member-Initiated Transmission Improvements.** Notice of the initiation of a transmission system improvement rated at 100 kV or above shall be made in accordance with the applicable Appendix A.

interconnection facilities, and the proposed structure and schedule for financing such facilities, including the identification of any known constraints to the use of such financed facilities by any Member;

(vii) If available, estimates of the cost of each planned reinforcement, including the proposed allocation of such costs to the forecasted transmission users;

(viii) Current, planned and expected uses, including economy transactions, of existing transmission facilities and transmission entitlements;

(ix) Generation resource additions and modifications;

(x) Identification of computer data bases and assumptions used for modeling the Member's existing and planned electrical systems; and

(xi) Any information required to be furnished in compliance with FERC regulations under Section 213 of the FPA.

4.7.5 Planned Resource Development. The Long Term Transmission Plans produced in the coordinated planning process can be accurate only to the extent that the resource plans reflected in the plans are accurate. Each utility Member and each non-utility Member is required to provide public domain information to the Planning Committee regarding its generation development plans and the requirements for transmission necessary to implement these plans. Such plans and requirements shall promptly be provided to the Planning Committee by a utility Member following Regulatory Authority approval and/or a decision of the governing body of the utility to develop a power resource, and by a non-utility Member following such non-utility Member's execution of a power sales agreement with respect to any power resource.

4.8 **Coordinated Planning Process.** Each Member that owns or plans to construct or acquire transmission facilities, or is otherwise entitled to transmission capacity, will biennially prepare a Long Term Transmission Plan, including supporting data and assumptions, and provide that Plan, and the supporting data and assumptions, to the Planning Committee as part of the coordinated planning process. The information shall be provided in the format specified by WSCC or, absent such format, by the Planning Committee. With respect to such Members, the process of preparing such Long Term Transmission Plan will consist of the following activities undertaken at times specified by the Planning Committee in the following order:

Member which designated the information as proprietary or confidential as soon as reasonably possible following the request so that such Member may assert any legal privilege, right, obligation or defense which it has. In addition, the Member against whom disclosure is sought may assert any available legal privilege or right to protect the proprietary nature or confidentiality of the information.

6.7 Planning Criteria

6.7.1 The applicable reliability criteria of NERC, WSCC, other electric reliability councils, and of the individual Member, shall govern the design and operation of each Member's transmission system. Individual Members' reliability criteria shall be consistent with Prudent Utility Practice and shall be consistently applied for internal system development and joint transmission facilities.

6.7.2 Transmission projects proposed within or through a Member's system should conform to that Member's planning criteria and the regional reliability criteria. The affected Member shall have the final determination as to whether a proposed project within its system meets its planning criteria. Each Member shall apply its planning criteria impartially and without undue discrimination.

6.7.3 Members recognize that in the operation of an integrated electric transmission system unscheduled flows will occur and may impact the overall operation of the integrated system. Members shall consider unscheduled flows in the design of new transmission projects and the provision of new services so as to minimize any detrimental impact, consistent with all applicable criteria, on Members' systems and other interconnected systems.

The Planning Committee shall determine (and each Member shall comply with) the type of data and representations to be submitted by each Member, which may include a description of all components of the transmission facilities represented by such data including the length, size, electrical characteristics and rating of transmission line segments; capacitor, circuit breaker, bus and/or transformer ratings (including emergency ratings if used in the design of the system); and other system elements to the extent such elements may limit transfer capability.

4.7.2 Planning Criteria. Each Member, when supplying transmission system data, shall also supply the transmission design, operating, and reliability criteria currently used in the planning of its transmission system.

7.3 Interrie Data. Each Member shall provide information specifying the transfer capability of each of its interties with other control areas for those interties at which such capabilities have been established and a summary of its contractual obligations to provide service, the amount of Firm Transmission Service, and other uses and commitments which affect these interties.

4.7.4 Long Term Transmission Plans. Each Member shall provide its Long Term Transmission Plan for new transmission facilities and reinforcements 100 kV and above and additional, associated interconnection facilities. The plan shall include a description of each transmission project including a single line diagram, the project's functional purpose and design parameters, the expected operating date, data required to incorporate the project in the utility's transmission representation and, for upgrades to system interconnections, the expected increase in transfer capability. Information on specific transmission projects less than 100 kV shall be provided as requested by the Planning Committee to facilitate coordinated planning. Each Long Term Transmission Plan shall include the following information for the applicable planning period:

(i) Existing and planned firm imports to meet the needs of Planned Native Load;

(ii) Existing and planned firm exports;

(iii) Existing contractual rights and commitments for transmission services;

(iv) Reservation for Prudent Reserve;

(v) The location, duration and quantities of Available Transmission Capacity on transmission lines or paths for which such transfer capabilities have been established;

(vi) Current plans for new transmission facilities at 100 kV and above and additional

schedule and cost information shall be made available to all Members and a reasonable amount of time shall be allowed for Members to elect to participate in the study. Those Members participating in the multi-party project studies shall periodically share the results of the study work with the Planning Committee.

6.4.3 Costs for multi-party planning studies shall be documented and shared on an equitable basis among those Members participating in the studies. Study costs may include computer costs, labor, report preparation, report distribution and appropriate overhead costs, as applicable.

6.4.4 Arrangements among Members participating in multi-party studies shall be documented by letter agreement or other appropriate instrument prior to the beginning of the studies.

6.4.5 Participation and ownership in any new transmission project that results from any multi-party study conducted pursuant to this Section 6.4 shall be documented by an ownership and participation agreement negotiated between the participating Members.

6.5 Confidential and Proprietary Information

Any data or information provided by Members in the planning process, or evaluations resulting from this process, which are designated as proprietary or confidential by the providing Member shall be treated as such by all Members which obtain or receive such data, information or evaluations and shall not be distributed to a non-Member without the previous consent of the Member providing such data or information, unless disclosure of the information is required by Section 213(b) of the FPA or other law. Each Member receiving such information shall make good faith efforts to protect the confidentiality of such information in any proceeding before a court or regulatory body. If a third party asserts a legal right to disclosure of proprietary or confidential information, the Member against whom disclosure is sought shall notify in writing the

transmission projects; and (v) consider opportunities for integrating their efforts with those of other transmission projects and for consolidation of transmission projects when practicable.

9.5.4 In addition to the provisions of Part 9.5.3, Members anticipating the development of major transmission projects (voltages greater than 100 kV) shall provide notice of opportunity to participate in development study work to all Members by posting notice in the Association's newsletter or electronic bulletin board. Members shall respond in writing to the sponsoring Members within 60 days after notice is posted indicating their desire to participate in and provide funding for such studies. Those Members participating in joint project studies shall periodically share the results of the study work with the Planning Committee. Costs for such joint planning studies shall be shared on an equitable basis among those Members participating as documented by an agreement between the parties. Study costs may include out-of-pocket expenditures for computer costs, staff time, report preparation, report distribution and appropriate overhead costs, as applicable.

9.5.5 The coordination of transmission planning by the Association shall not require a Member to implement any specific proposals which are the result of any Planning Committee or Board action; provided, however, no Member shall be relieved of its obligation to respond to requests for transmission services as required by this Governing Agreement or to implement the provisions of a contract or Award.

shall notify the Member who designated the information confidential as soon as reasonably possible following the request so that such Member may assert any legal privileges, rights, obligations or defenses.

4.6.4 Use of Computer Models, Software and Programs. Any computer model, software or program which is utilized by a Member to produce any data or information required to be provided under these Bylaws (including all data, information and testimony provided in any Binding Arbitration Proceeding) must be identified by such Member and available to other Members by purchase, license or other commercially reasonable means. If the computer model, software or program is not so available, the Member utilizing such computer model, software or program shall provide, upon written request from a requesting Member, a copy or make it readily accessible to any requesting Member to allow the requesting Member to verify such data or information provided by the Member. Each Member utilizing a computer model, software or program to produce such data or information must also provide all assumptions, equations, data and information utilized to produce the data or information so that any Member may independently verify and assess such computer model, software or program.

4.7 **Initial and Biennial Information.** Except as otherwise determined by the Planning Committee, each Member shall provide to the Planning Committee the assumptions and data identified in Section 4.8.2 and the following information, where applicable, within 6 months (or such other time frame as determined by the Planning Committee) of the effective date of these Bylaws and thereafter at the beginning of each biennial planning cycle (as specified by the Planning Committee). However, the assumptions and data identified in Section 4.8.2 and the following information shall not be required to be provided by a Member when it is available through the WSCC unless another Member cannot obtain such information through WSCC. In such event, a Member shall provide such assumptions, data or information to another Member promptly following receipt of a written request therefor.

The following information shall be provided in the format specified by WSCC or, absent such format, by the Planning Committee.

4.7.1 Transmission System Data and Representation. Each Member that operates a control area shall, for the current year summer peak, provide generation and transmission system data and system representations, including applicable system constrained conditions, of all existing transmission facilities within its control area operated above 100 kV relevant to the coordinated planning process. Such data and representations shall, to the extent feasible, be consistent with those prepared for planning studies of the appropriate regional reliability council. Each Member shall cooperate with the control area operator in fulfilling the requirements of this Section 4.7 and Section 4.8.2.

are to be reported and the format of the data, to assure that SWRTA's objectives are met. The data submitted by each Member for its Interconnected Transmission System should be provided in WSCC format and should include, at a minimum, data necessary to comply with Section 213(b) of the FPA and FERC rules and regulations promulgated thereunder. This information includes, but is not limited to, the following:

6.3.1 Planned transmission and resource additions

6.3.2 Projected load and resource data

6.3.3 Existing and forecasted transmission service arrangements

6.3.4 Individual planning criteria used by each Member to plan its transmission system

6.3.5 Available Transmission Capacity data for the major interconnection points and transfer paths identified by the Planning Committee

6.3.6 Map of existing transmission system and planned additions

If requested by other Members, Members shall provide data from transmission studies in sufficient detail for use by other Members. The Members shall expand the WSCC system representation to the maximum extent possible to meet Member study needs.

6.4 Planning Coordination

6.4.1 No Member shall be required to accept a planning recommendation made by the Planning Committee or the Board.

6.4.2 The opportunity to participate in a study of any new transmission project that impacts the Interconnected Transmission System and to ultimately participate in such new transmission project shall be made available to all Members. Members involved in the development of transmission projects that impact the Interconnected Transmission System shall send written invitations to all Members to attend the initial information/planning meeting for such project. After the initial meeting, the study scope,

the individual Transmission Provider. Individual Transmission Providers' reliability criteria, standards, guidelines and operating procedures shall be reasonable and consistent with Prudent Utility Practice and shall be consistently applied in determining Available Transmission Capacity, determining the availability of transmission capacity for the Transmission Provider's own uses and in determining what Incremental Facilities are required.

9.5 Planning Coordination. Within the Association, planning coordination shall facilitate the integration of each Member's individual transmission system expansion plans through cooperative action with other Members who are developing or planning transmission projects. While the responsibility to actually perform system planning shall remain with individual Members, the Association, though the Planning Committee, shall provide for the coordination of the planning efforts of all Members in order to further the goal of developing a reliable and efficient transmission system.

9.5.1 The Planning Committee shall make information on planned transmission facilities, including present and future Available Transmission Capacity where known, available to Members.

9.5.2 The Planning Committee shall support the development of technical study capabilities, as needed, for regional transmission assessments.

9.5.3 Members developing transmission projects shall: (i) include the known needs of Members and non-Members whenever practicable; (ii) look beyond the proposed terminus of their own proposed transmission projects in order to consider opportunities to improve regional operation and resource utilization; (iii) address the efficient use of transmission corridors; (iv) seek comment from other parties affected by

parallel path flows will occur and may be beneficial or detrimental to the overall operation of a Member's system. Coordinated planning under these Bylaws shall take into account parallel path flows in the design of new projects and the provision of new services so as to mitigate, consistent with Prudent Utility Practice, the detrimental effects of parallel path flows on each Member's system and utility systems interconnected thereto.

4.5 **Repository for Planning Information.** The Planning Committee shall establish or designate a repository and develop all necessary operating and procedural matters related thereto, including a process to access all planning information obtained through these Bylaws. Each Member shall comply with all such operating and procedural matters. Such planning information shall be accessible to all Members. The Planning Committee will coordinate system data requirements in order to help Members identify Available Transmission Capacity.

Member Requests for Information from other Members; Costs of Requests; Confidential Information; Restricted Software.

4.6.1 Request for Information from other Members. If a Member desires information which is unavailable in the data repository established pursuant to Section 4.5, such Member may request from any other Member, and such other Member shall provide within a reasonable period of time from receipt of the request, electrical system data and representations for the specified portion of its transmission facilities and any other information about its system requested by such Member which is reasonably necessary in order to permit such Member to: (i) assess Available Transmission Capacity; (ii) assess the need for, and system performance associated with, new transmission facilities, to the degree not represented in the repository; or (iii) undertake or enforce any right or obligation specifically provided under these Bylaws.

4.6.2 Costs of Request Paid by Requesting Member. The Member requesting such data and information is obligated to pay the other Member's reasonable costs for providing the requested data and information.

4.6.3 Data Treated as Confidential. Any data or information which is received from another Member pursuant to Section 4.6.1 which is designated as confidential by the providing Member shall be treated as confidential by all Members which obtain or receive such data or information and shall not be distributed to a non-Member without the previous consent of the Member providing such data or information. Each Member receiving such information shall make good-faith efforts to protect the confidentiality of such information in any proceeding before a court or regulatory body. If a third party asserts a legal right to disclosure of confidential information, the Member against which disclosure is sought

6.1.6 Facilitate the planning and construction of new transmission facilities by interfacing with WSCC and other RTGs or regional planning groups.

6.1.7 Upon the request of a Member and the approval of the Planning Committee, support a Member's regulatory approval process by evaluating whether a new transmission project meets Members' needs.

6.1.8 Ensure that information regarding studies for new transmission projects and any reports issued pursuant to Section 6.1.9 hereof are available to all Members.

6.1.9 Prepare appropriate planning reports and maps, as requested, for regulatory agencies, reliability councils and others, as requested, including coordinating Transmitting Member reports to FERC as required under Section 213(b) of the FPA and any applicable rules and regulations promulgated thereunder.

6.1.10 Perform technical studies as directed by the Board.

6.1.11 Carry out other activities as directed by the Board.

6.2 Involvement of Interested Parties in the Planning Committee

The Chairman of the Planning Committee shall maintain a distribution list of Interested Parties which have an interest in transmission planning activities coordinated by the Planning Committee. Any Member may add Interested Parties to the distribution list. The Chairman of the Planning Committee shall have the responsibility to notify and invite the Interested Parties to Planning Committee meetings. Such Interested Parties may attend and participate in all Planning Committee meetings, but shall not have a right to vote on matters coming before the committee.

6.3 Planning Information

Each Member shall file information regarding its existing and planned Interconnected Transmission System over a ten (10) year horizon on an annual basis with the Planning Committee. The Planning Committee will determine what data are required, including the years for which the data

make submissions of required data as requested by the Planning Committee. The Planning Committee may also designate data which will normally be made available by Members to other Members upon request which is not collected by the Association.

9.3.1 To avoid unnecessary duplication among the Association, WSCC or Subregional Coordination Groups which may be collecting and coordinating transmission planning information, the Planning Committee shall, to the maximum extent practicable, coordinate its data collection activities with such entities, use WSCC reports and data, and adopt formats established by the WSCC to fulfill the information reporting requirements of this section.

9.3.2 Data collected directly by the Association, or in cooperation with the WSCC or other entities, shall be available through the Association regardless of its physical location. If a Member desires information which is not collected by or through the Association, such Member may request from any other Member electrical system data and representations for the specified portion of its transmission facilities and any other information which is reasonably necessary for such Member to: (i) assess Available Transmission Capacity; (ii) assess the need for, and the system performance associated with, new transmission facilities, to the degree not represented in Association collected data; or (iii) undertake or enforce any right or obligation specifically provided under these Bylaws. A Member receiving such a request for data and information shall provide it within a reasonable time after receipt of the request. The Member requesting such data and information shall be obligated to pay the other Member's reasonable costs for providing the requested data and information.

9.4 Planning Criteria. Planning, design and operation of each Member's system shall be governed by the reliability criteria, standards, guidelines and operating procedures of the North American Electric Reliability Council, the WSCC, and of

COORDINATED TRANSMISSION PLANNING

WATSCO

4. COORDINATED TRANSMISSION PLANNING:

4.1 Purpose of Coordinated Transmission Planning. Each Member shall provide information requested by the Planning Committee to facilitate coordinated transmission planning. The Planning Committee will emphasize: reliability planning; the efficient use and operation of transmission systems; and the construction of new facilities or reinforcements to existing transmission systems in order to accommodate existing and planned transmission needs. For the purpose of establishing a clear understanding of the operating capabilities and constraints of the transmission system, each Member shall provide to the Planning Committee information (which to the greatest extent practicable shall be based upon information which may be verified by any other Member) about such Member's (i) existing and planned electric system and transmission entitlements and (ii) transmission needs.

4.2 Planning Criteria. With respect to all planning activities under these Bylaws, the following criteria shall govern:

4.2.1 Applicable Reliability Criteria - The applicable reliability criteria and guidelines of NERC and WSCC, and each individual Member's reliability criteria shall govern the planning, design and operation of such Member's system. Each Member utility's reliability criteria shall be consistent with Prudent Utility Practice and shall be Consistently Applied.

4.2.2 WATSCO Planning Criteria - Such other planning criteria as developed by the Planning Committee and approved by the Board.

Except where the affected Member(s) agrees otherwise, the standard set forth in Sections 4.2.1 and 4.2.2 which results in maintaining the highest degree of reliability shall apply.

4.3 New Projects. Members may request interconnection of new transmission projects and generation resources in accordance with these Bylaws. Each Member acknowledges that new transmission projects and generation resources will affect existing transmission systems. New transmission projects and generation resources (to the extent generation resources impact transmission system reliability) (i) shall conform with reliability criteria as set forth in Section 4.2 and (ii) shall not reduce pre-existing transfer capabilities of any Member's system, except by mutual agreement among affected Members. In any Dispute Resolution Proceeding in which it is asserted that the new project unreasonably impairs the continued reliability (based upon consistently applied NERC, WSCC and an affected Member's reliability criteria and guidelines) of any Member's electric system, the burden of proof with respect to such impairment shall be on the party asserting the impairment. Interconnection of a transmission or generation project shall be requested and implemented in a separate contract, all in accordance with Section 5 of these Bylaws.

4.4 Parallel Path Flows. Each Member recognizes that in the operation of an integrated electric transmission system,

SWRTA

6. COORDINATED PLANNING:

6.1 Planning Committee Functions

Membership on the Planning Committee shall be open to all Members; ex officio membership on the Planning Committee shall be open to all Commission staffs. Any Member or Commission that wishes to participate on the Planning Committee shall appoint a representative to the committee. The Planning Committee shall provide a forum for coordination of planning activities within SWRTA by facilitating the prompt exchange of information among Members through use of a common WSCC data base, timely responses by Members to requests for transmission service, development of multi-party transmission projects to serve the needs of all Members, and SWRTA's interface with other industry organizations, including other RTGs and regional planning groups. To carry out these responsibilities, the Planning Committee shall:

6.1.1 Provide a forum for coordinating transmission plans, sharing system data, and jointly developing new transmission projects.

6.1.2 Annually review and document the ten (10) year transmission and resource plans submitted by the Members.

6.1.3 By the most economic means available, including, but not limited to, an electronic bulletin board, collect and disseminate or cause to be made available such Member information, data and transmission plans as are determined to be necessary by the Planning Committee for SWRTA to meet its objectives.

6.1.4 Review and make available to all Members the internal planning criteria of individual Members.

6.1.5 Support consistent and timely responses to Member requests for transmission service, including, upon the request of a Member, reviewing for reasonableness responses to requests for transmission service, study agreements negotiated pursuant to Section 3.3 hereof between Transmitting and Requesting Members, and the results of those study agreements.

WRTA

9. COORDINATED PLANNING AND ACCESS.

9.1 Planning Committee Purpose. The purpose of the Planning Committee shall be to assist the Members in meeting their transmission needs and in fulfilling their service obligations under this Governing Agreement. The goal of coordinated planning within the Association is to assure the development of an efficient and reliable regional transmission system in the Western Interconnection consistent with the WSCC reliability criteria. To further the advancement of such goal, the Planning Committee shall take such actions as necessary to provide for the effective coordination of Members' transmission planning activities.

9.2 Planning Committee Functions. To carry out these purposes, the Planning Committee shall:

9.2.1 Cause to be collected, and made available to all Members, the planning information described in Subsection 9.3.

9.2.2 Establish procedures which provide for development of coordinated transmission plans as described in Subsection 9.4;

9.2.3 Prepare, when appropriate, Association planning information, reports and maps for government regulatory agencies, reliability councils and others, as requested;

9.2.4 Encourage the use of common and consistent planning assumptions and methods among Members to the maximum extent practicable;

9.2.5 Promote and encourage the efficient use and development of the region's existing and future transmission facilities that will enhance interconnected operations; and

9.2.6 Carry out other activities as directed by the Board.

9.3 Planning Information. The Planning Committee shall determine the information which is required to execute its functions as described in Subsection 9.1 and which is generally required to meet the planning needs of Members. To facilitate collection of such data, each Member of the Association shall

COORDINATED TRANSMISSION PLANNING

6. **MEMBERS BOUND BY AND TO SUPPORT WATSCO DECISIONS; SUBMIT MATTERS REGARDING PERMITS AND APPROVALS IN TIMELY MANNER:**

6.1 **Certain Members Bound By Decisions.** Except as specifically provided otherwise in these Bylaws, each Member which participates in a process (or receives written notice that its rights may be affected thereby in sufficient time to participate in such process) resulting in a decision, resolution or action in connection with or required by these Bylaws shall be bound by such result. A decision in Binding Arbitration Proceeding shall not be a precedent for a decision in any other Binding Arbitration Proceeding.

6.2 **Participating Members Support Decisions Before Regulatory Authorities.** Except as specifically provided otherwise in these Bylaws, each Member which participates in a process resulting in a decision, resolution or action in connection with or required by these Bylaws shall fully support such decision, resolution or action in connection with or required by these Bylaws before any Regulatory Authority.

6.3 **Submit Matters in Timely Manner to Obtain Review, Permit or Approval.** Except as specifically provided otherwise (i) by mutual agreement among affected Members or (ii) in these Bylaws, each decision, resolution or action in connection with or required by these Bylaws which requires any review, permit or approval shall be submitted in a timely manner in order to obtain such review, permit or approval.

7. **NO IMPACT ON CONTRACTS; ABILITY TO CONTRACT OUTSIDE WATSCO; NEGOTIATE CONTRACTS CONSISTENT WITH BYLAWS:**

7.1 **No Impact on Contracts or Other Legal Obligations.** These Bylaws do not replace or modify, supersede, or limit any contract, decision of regulatory agencies or courts of law, or other legally enforceable entitlement, right or obligation of any Member except as specifically provided in Section 5.11.

7.2 **Negotiated Contracts Notwithstanding Bylaws.** Notwithstanding any provision of these Bylaws to the contrary, any Member may agree and/or contract with any other Member regarding any mutually agreeable term or condition for transmission service or for other services under a contract (i) otherwise in accordance with these Bylaws or (ii) without regard to these Bylaws. Nothing in these Bylaws shall restrict the rights of Members to provide transmission services to non-Members under separate contract.

7.3 **Good Faith Efforts to Negotiate Contracts Under Bylaws.** Each Member shall make good faith efforts to negotiate definitive contracts, as appropriate, to provide requested transmission service, including any Incremental Additions, in accordance with these Bylaws.

8.5.3 Effect of Expulsion. In the event that a Member is expelled pursuant to Section 8.5.2, any pending requests by such Member for transmission service in accordance with these Bylaws shall be null and void as of the effective date of such expulsion.

12. FAILURE TO DISCHARGE OBLIGATIONS; SPECIFIC PERFORMANCE REMEDY:

12.1 **Failure to Discharge Obligations Under These Bylaws.** Except as otherwise determined by the Board of Directors, any Member which fails to comply with any of its duties or obligations under these Bylaws, following notice thereof and a reasonable time to cure such breach, shall not be entitled (i) to receive under these Bylaws any information, data or plans as set forth in Section 4, (ii) to access to the repository established pursuant to Section 4.5, or (iii) to vote with respect to any matter before the Planning Committee or the Board of Directors. Any member who is accused of a failure to comply with any of its duties or obligations under these Bylaws shall not be entitled to vote on whether it has so failed or on the issuance of the notice of such failure.

12.2 **Specific Performance.** In the event a Member files a legal action against another Member for breach of a duty or obligation arising under Section 4, any court may, as a nonexclusive remedy and in addition to any other remedy available in law or equity, order such Member to specifically perform such obligation or duty.

8.6 **List of Members.** Appendix B lists the entities which are currently Members of WATSCO. Appendix B shall also list the entities which have withdrawn from membership, have been expelled from membership, and have been reinstated as Members of WATSCO. The dates of each such event shall be included in Appendix B.

8.5 Members Subject to Disciplinary Action.

8.5.1 No Member Engage in Bad Faith Conduct. No Member may engage in bad faith conduct in connection with any duty or obligation arising out of the Bylaws. For example, a Transmission Provider may not refuse to respond to a Member's transmission request under Section 5 and the applicable Appendix A on the basis that, in the Transmission Provider's opinion, the Transmission Requester does not need or require the requested transmission service. A Member who engages in bad faith conduct under these Bylaws shall be subject to disciplinary action under Section 8.5.2, as well as any other legal recourse that an aggrieved Member may have against such offending Member.

8.5.2 Complaint Alleging Bad Faith Conduct of Member. Upon receipt by the Board of a written complaint of a Member alleging that another Member has engaged in bad faith conduct in connection with any duty or obligation arising out of the Bylaws, including any resolution or other action implementing the Bylaws, or arising out of any Dispute Resolution Proceeding decision, the Board or its designee, shall conduct a reasonable inquiry into such allegations. The Board may adopt procedural rules for conducting hearings and receiving evidence concerning allegations of bad faith conduct. If the Board or its designee, following a reasonable inquiry, finds that a Member has engaged in bad faith conduct, then the Board, on a 2/3 majority vote, shall take appropriate disciplinary action, which may include but shall not be limited to any of the following (including any combination thereof):

i) Issue a written reprimand and warning to the offending Member;

ii) Advise any Regulatory Authority of the offending Member's bad faith conduct; or

iii) Expel the offending Member from WATSCO, provided that said expulsion shall have no effect on the validity or enforceability of any contract or Dispute Resolution Proceeding decision which is in effect as of the effective date of the expulsion.

The decision of the Board imposing disciplinary action under this section shall be final, and shall not be subject to the Dispute Resolution Procedure. Any disciplinary action provided under this Section shall not be deemed to be an exclusive remedy, but shall be in addition to any legal or equitable remedy that is available to an aggrieved Member.

11.4 Suspension or Termination of Membership

Any time that a Member becomes delinquent in the payment of administrative costs incurred during its membership and fails after ninety (90) days of receipt of a written notice to pay such costs, or that the Board by resolution finds that a Member has (i) intentionally or repeatedly violated any SWRTA Bylaw, or (ii) materially breached or intentionally violated any FERC order or arbitration decision issued pursuant to these Bylaws, or (iii) willfully obstructed any lawful purpose or activity of SWRTA, the Board, at its sole discretion, may suspend or terminate that membership. The affected Member shall be given sixty (60) days advance written notice of any Board meeting at which suspension or termination action against that Member is anticipated and such Member shall have the right to be present and to present information concerning the suspension or termination action to the Board. Upon suspension or termination of membership, the Member's voting rights and all other rights and privileges of membership shall automatically cease. Notice of suspension or termination shall not change the Member's obligation under any contract, FERC order, unpaid Member cost, decision of arbitration, or request for transmission service in effect or pending as of the effective date of suspension or termination, unless otherwise agreed by any affected Member. The Board shall promptly notify FERC in writing of any Member suspended or terminated pursuant to this Section 11.4. Any costs associated with providing such written notice of termination to FERC shall be paid by the terminated Member.

11.5 Restrictions on Resumption of Membership

A Member which has withdrawn from membership may not apply for reinstatement to membership for a period of one (1) year unless otherwise determined by action of the Board. A Member which has been terminated from membership may not apply for reinstatement to membership for a period of time stated in the Board resolution of termination, not to exceed five (5) years.

3.4 Termination of Membership. At any time that a Member becomes delinquent in the payment of any administrative and operating costs which are incurred during its membership and fails after 90 days of receipt of a written notice to pay such costs, or if the Board finds that a Member has: (i) intentionally or repeatedly violated any Bylaw of the Association, (ii) breached or violated any Award issued pursuant to its membership in the Association, or (iii) willfully obstructed any lawful purpose or activity of the Association or if the Board finds that governmental or judicial bodies have imposed requirements or restrictions on such Member which materially impede such Member's ability to fulfill its obligations pursuant to this Governing Agreement, the Board, in its sole discretion, may terminate the Member's membership. The affected Member shall be afforded at least 21 days advance written notice of any Board meeting at which termination of the Member will be considered and such Member shall have the right to be present and present information to the Board concerning any proposed termination action. Upon termination of membership, all of the Member's voting rights and other rights of membership shall cease. Notwithstanding such notice of termination, all Awards and requests for transmission service to be provided by such Member in effect or pending as of the effective date of termination shall be honored by the terminated Member; provided, however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of this Governing Agreement. A Member which has been terminated from membership may not reapply for membership for a period of time stated in the Board resolution of termination, which shall not exceed a period of five years.

11.4 **Withdrawal From Membership.**

11.4.1 Applicants and Members Withdrawal Approved by FERC. The Applicants subject to FERC jurisdiction under Section 205 of the FPA hereby request FERC to approve the right of such an Applicant or Member to unilaterally terminate its participation in these Bylaws and to unilaterally withdraw as an Applicant or Member, pursuant to the terms of these Bylaws, without the necessity of further filing with or approval by FERC. Applicants or Members have the right to unilaterally terminate their participation in these Bylaws and to unilaterally withdraw as an Applicant or Member, pursuant to the terms of these Bylaws, without the necessity of filing with or approval by FERC.

11.4.2 No Opposition to Withdrawal of any Applicant or Member. No Applicant or Member shall oppose, before any Regulatory Authority or court, any other Applicant's or Member's withdrawal as provided in these Bylaws.

8.3 **Foreign Members.** The Members agree to enter into good-faith negotiations with electric utilities or electric power producers which are not located in the United States regarding membership in WATSCO. Issues to be negotiated include, but are not limited to, (i) the appeal process, if any, of a decision rendered in a Binding Arbitration Proceeding involving Members located outside the United States, and (ii) the means to enforce the provisions of, and the contracts executed in accordance with, the Bylaws where Members are located outside the United States.

8.4 **Withdrawal from Membership.**

8.4.1 Right of Withdrawal From Membership. Any Member may withdraw from membership effective upon receipt by the Board of written notice thereof. Any request submitted to a withdrawing Member for transmission service in accordance with Section 5 and the applicable Appendix A with a notice date prior to the effective date of withdrawal shall be processed and determined (including a Dispute Resolution Proceeding) in accordance with the provisions of these Bylaws in effect as of the date of withdrawal as if the withdrawing Member were still a Member of WATSCO. Any request submitted by a withdrawing Member for transmission service in accordance with Section 5 and the applicable Appendix A shall be deemed null and void if, prior to the completion of processing such request (including a Dispute Resolution Proceeding related thereto) for transmission service in accordance with these Bylaws, the Transmission Requester withdraws from membership in WATSCO.

8.4.2 Withdrawal No Effect on Contracts or Member's Outstanding Fees/Costs. A Member's withdrawal of its membership in WATSCO pursuant to this Section 8.4 shall have no effect on the validity or enforceability of any contract or decision rendered pursuant to a Dispute Resolution Proceeding which is in effect as of the effective date of withdrawal. A withdrawing Member shall continue to be liable for any unpaid cost or fees properly assessed or attributable to such Member under these Bylaws prior to the effective date of the withdrawal.

8.4.3 Withdrawing Member's Rights in a Binding Arbitration Proceeding. Any withdrawing Member which is an Initiating Party to a Binding Arbitration Proceeding may terminate such Binding Arbitration Proceeding unless the Panel determines that it is in the public interest to render a decision in such Binding Arbitration Proceeding. Any withdrawing Member which is a Respondent or an Indispensable Intervener in a Binding Arbitration Proceeding (i) may not withdraw from the Binding Arbitration Proceeding without the written permission of all other Parties and (ii) shall have the same rights, duties and obligations in such Binding Arbitration Proceeding as if the withdrawing Member were still a Member of WATSCO.

11.3 Withdrawal from Membership

Any Member may withdraw from SWRTA by providing written notice to the Board and to FERC. Any costs associated with providing written notice of its withdrawal to FERC shall be paid by the withdrawing Member. Notwithstanding such notice of withdrawal, all contracts, FERC orders, unpaid administrative costs, decisions of arbitration and requests for transmission service in effect or pending as of the date of the written notice of withdrawal shall be followed to completion, pursuant to these Bylaws, by the withdrawing Member; however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of these Bylaws.

3.3 Withdrawal from Membership. Any Member may withdraw from the Association upon providing written notice of its withdrawal to the Board and the FERC. Notwithstanding such notice of withdrawal, all Awards, arbitration proceedings and requests for transmission service to be provided by such Member in effect or pending as of the date of the receipt by the Board of written notice of withdrawal shall be followed to completion pursuant to this Governing Agreement by the withdrawing Member; provided, however, pending requests for transmission service to be provided to such withdrawing Member shall be void for purposes of this Governing Agreement. Any Member which has voluntarily withdrawn from the Association may not reapply for Membership for a period of one year from the date of its withdrawal.

MEMBERSHIP

WATSCO

8.1 **Initial Membership; Membership Eligibility; Ex Officio Members.**

8.1.1 Initial Membership. Initial membership in WATSCO shall be open to any entity eligible to request, or which could be required to provide, a service under Section 211 of the FPA.

8.1.2 Regulatory/Governmental Agencies Ex Officio Members: Rights of Such Members. Representatives of appropriate regulatory and/or governmental agencies may be ex officio members of the Board of Directors and the Planning Committee. The Board of Directors shall designate from time to time no more than two representatives from such regulatory and/or governmental agencies from each State in which a Member is subject to such regulatory and/or governmental agency (at least one of which shall be from the State's public utility commission or its equivalent, and at least one of which shall be from an energy commission where such a commission exists) to be ex officio members of the Board of Directors and the Planning Committee. Each such representative shall be entitled to participate in all meetings or proceedings under these Bylaws in the same manner as Members and receive notices, information and data under these Bylaws in the same manner and under the same procedures as Members; provided, however, such representative shall have no voting rights on the Board of Directors or the Planning Committee.

8.2 **Membership Following Effective Date of Bylaws.** Following the effective date of the Bylaws, non-Member entities desiring to join WATSCO must submit to the Board a written request for membership. Membership must be granted to entities who meet the eligibility requirements of Section 8.1 and who commit to be bound by the Bylaws (subject to membership being granted to WATSCO) unless (i) the Board finds by a 2/3 majority vote of each category of Members that the entity seeking membership is ineligible for membership under these Bylaws or (ii) the entity seeking membership was previously expelled under the terms of Section 8.5. Membership may be granted to foreign organizations, entities which have previously withdrawn their membership or were previously expelled under the terms of Section 8.5 or any other entities upon a determination of the Board to grant such membership by a 2/3 majority vote of each category of membership. Concurrent with the determination of the Board to grant membership, the Board shall determine which category of membership such new Member shall be assigned. As a condition of membership, the Members of the category of membership to which such new Member is assigned to may require, by majority vote of all Members in such category of membership, such new Member to reimburse such Members for a proportionate share (or a smaller amount) of the costs of obtaining FERC approval of these Bylaws which were borne by the Members of such category of membership.

SWRTA

11. MEMBERSHIP:

11.1 Classifications of Members

Any entity that meets the qualifications for membership set forth in Section 2.11 hereof and signs these Bylaws shall notify the Board in writing and elect classification in the Member Class, as defined in Section 2.12 hereof, that best describes its status or most closely aligns with its interests. Upon the Board's determination that the entity has met the qualifications for membership and selected an appropriate Member Class, the new Member shall pay the annual membership fee pursuant to Section 16 hereof and Appendix A hereto, and shall notify FERC in writing of its membership and Member Class in SWRTA. A Member may change its Member Class by providing written notification to the Board and to FERC at least five (5) days prior to the annual meeting of Members.

11.2 Membership Responsibilities

Each Member shall meet all obligations of membership described in these Bylaws.

WRTA

3. MEMBERSHIP.

3.1 Qualifications. Any entity meeting the definition of a "Member," set forth in Subsection 2.15, shall be admitted to membership in the Association upon executing this Governing Agreement and providing notice of its having done so to the Board and FERC.

3.2 Classifications of Members. Upon being admitted for membership, each Member shall designate which one of the following classifications of Members to which it wishes to be assigned:

a. Major Transmitting Utility

b. Transmission-Dependent Utility

c. Nonutility Supplier

d. Commission

MEMBERSHIP

3.44 **Transmission Requester** - Any Member or Members requesting transmission service from a Transmission Provider pursuant to Section 5 and the applicable Appendix A.

3.45 **Type 1 Transaction** - Any transaction between or among Members, if the Transmission Provider is subject to FPA Sections 205 and 206.

3.46 **Type 2 Transaction** - Any transaction between or among Members, if the Transmission Provider is not subject to FPA Sections 205 and 206.

3.47 **Uncontrollable Force** - Any cause beyond the control of the Member affected, including, but not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, pestilence, lightning or other natural catastrophes, epidemic, famine, war, riot, civil disturbance or disobedience, labor dispute, strike, labor or material shortage, sabotage, government priorities, restraint by court order or public authority, and action or non-action by or inability to obtain necessary authorizations or approvals from any governmental agency or authority which, by acting consistent with Prudent Utility Practice, due diligence and foresight, such Member could not reasonably have been expected to avoid and which, by exercise of due diligence, it has been unable to overcome.

3.48 **WSCC** - The Western Systems Coordinating Council.

3.49 **Zone of Reasonableness** - Defined in Section 9.1(iv).

2.21 WSCC: The Western Systems Coordinating Council.

2.21 Prudent Utility Practice. Those practices, methods and acts, including levels of reserves and provisions for contingencies, as may be modified from time to time, that are commonly used in the Western Interconnection to: (i) plan, design and operate electric systems in a manner that is dependable, reliable, safe, efficient, economical and in accordance with all applicable laws and governmental rules, regulations and orders and consistent with the provisions of the reliability criteria, standards, guidelines and operating procedures of the North American Electric Reliability Council and of the WSCC which govern the planning, design and operation of Members' transmission systems; (ii) serve customers; and (iii) prevent material adverse effects on neighboring systems.

2.22 Subregional Coordination Groups. Voluntary subregional associations involving Members that may be organized from time to time to exchange information and coordinate local transmission planning in subregions of the Western Interconnection.

2.23 Transmission Provider. Any Member owning or having contractual rights to use transmission facilities located in the Western Interconnection who can be required to provide a transmission service pursuant to Section 211 of the FPA or any such Member who could be so required were it located within the United States.

2.24 Transmission User. Any Member entitled to apply to the FERC for an order requiring transmission services pursuant to Section 211 of the FPA or any Member that is located outside the United States that would be entitled to apply for such an order were it located within the United States.

2.25 Western Interconnection. The area comprising those states and provinces in Western Canada, Northern Mexico and the Western United States in which Transmission Providers, which are members of the WSCC, operate synchronously-connected transmission systems.

2.26 WSCC. The Western Systems Coordinating Council.

commission or other Regulatory Authority proceeding; provided however, if a Member has no forecast load approved by a Regulatory Authority, the Member shall utilize its forecast load as set forth in its transmission plans as required in Section 4.7.

3.33 **Planning Committee** - The Planning Committee established pursuant to Section 9.

3.34 **Proposal** - Defined in Section 10.9.3.

3.35 **Prudent Reserve**- An amount of transmission capacity set aside for a Member's reasonable reliability requirements consistent with Prudent Utility Practice.

3.36 **Prudent Utility Practice** - Those standards (including then-current published reliability criteria, standards and guidelines of the WSCC and NERC, and the reliability criteria, standards and guidelines of the Member published as of January 1, 1993), practices, methods and equipment that are currently and commonly used by electric utilities to plan, engineer, select, operate, schedule and maintain electric power facilities and equipment reliably and efficiently to serve their customers dependably and economically with due regard for the conservation of natural resources, protection of the environment and the state of the art in the electric power industry as applied in the WSCC area.

3.37 **Radial Transmission Facilities** - Facilities which:

(i) Interconnect two or more electrical control areas; or

(ii) Are identified as radial transmission line(s) pursuant to contract; or

(iii) Are functionally separate from the Transmission Provider's integrated network such that the facilities are, or can be, operated and planned as a single facility; or

(iv) Interconnect a Transmission Requester's generation resource with a Transmission Provider's system at a single point.

3.38 **Regular Arbitration** - Defined in Section 10.8.3.

3.39 **Regulatory Authority** - Any state regulatory agency or local governing body acting as a regulatory body, and any federal regulatory body, including FERC, with jurisdiction over a decision, resolution or action arising in connection with these Bylaws.

3.40 **Respondent** - Defined in Section 10.6.2.

3.41 **Response** - Defined in Section 10.6.4

3.42 **System Jeopardy** - Defined in Section 5.8.

3.43 **Transmission Provider** - Any Member which (i) possesses contractual rights to, (ii) owns, or (iii) operates capacity in electric power transmission facilities which are used for the transmission of electrical power for sale of electric energy at wholesale.

2.13 Native Load: Load associated with existing and future retail customers and full or partial requirements wholesale customers for which a Member, by statute, franchise, contract, or federal, state or provincial policy or regulation, has undertaken or otherwise has the obligation to plan, construct and operate its system to provide reliable service.

2.14 NERC: The North American Electric Reliability Council.

2.15 Ownership-Like Rights: The rights, benefits and obligations associated with ownership of specified transmission capacity resulting from construction of Incremental Facilities, including, but not limited to, the right to use, assign, sell or otherwise dispose of such transmission capacity, and the financial obligation to pay for all costs, including, but not limited to, operation, maintenance or replacement costs and taxes allocated to such Incremental Facility, but excluding legal title and the responsibility for physically operating, maintaining and replacing such Incremental Facilities.

2.16 Planning Committee: The committee described in Section 6.1 hereof.

2.17 Prudent Utility Practice: Those practices, methods and acts, including levels of reserves and provisions for contingencies, as may be modified from time to time, that are commonly used by electric utilities in the western United States to (i) operate electric systems dependably, reliably, safely, efficiently, economically, and in accordance with all applicable laws and governmental rules, regulations and orders; (ii) serve customers; and (iii) prevent adverse effects on neighboring electric systems and control areas.

2.19 Requesting Member: Any Member that requests transmission service from any other Member or Members.

2.20 Transmitting Member: Any Member which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.

2.16 Native Load. Load associated with retail customers and full or partial requirements wholesale customers for which a Transmission Provider, by statute, franchise, contract or federal, state or provincial policy or regulation, has undertaken or otherwise has the obligation to plan, construct and operate its system to provide reliable service.

2.17 Ownership-Like Rights. The rights, benefits and obligations associated with ownership of a fixed amount of transmission capacity (which shall not be affected by future rerating) resulting from construction of Incremental Facilities, including the right to use, assign, sell or otherwise dispose of such transmission capacity, and the financial obligation to pay for all costs, including, but not limited to, operation, maintenance or replacement costs and taxes allocated to such Incremental Facility, but excluding legal title, the cost of upgrades and the authority and responsibility for operating, maintaining and replacing such Incremental Facilities. Costs to be borne by the recipient of Ownership-Like Rights shall be reasonable and consistent with Prudent Utility Practice and subject to reasonable provisions for auditing and oversight of such expenses.

2.18 Planning Committee. The Committee described in Subsection 9.1.

2.19 Power Marketing Agency. The Western Area Power Administration or the Bonneville Power Administration.

2.20 Prudent Reserve. An amount of transmission capacity set aside for a Transmission Provider's reasonable reliability requirements as determined by the reliability criteria standards, guidelines or operating procedures of such Member which shall be consistent with Prudent Utility Practice and regional reliability council criteria, standards, guidelines or operating procedures, which requirements shall be impartially applied without undue discrimination.

3.14 **Firm Transmission Service** - Transmission service that is subject to interruption or curtailment only for insufficient transfer capability (e.g., forced outages, abnormal system operating conditions, or scheduled maintenance) or system jeopardies.

3.15 **FPA** - The Federal Power Act, as amended.

3.16 **Generic Tariff** - A tariff, lawfully filed with FERC, containing pricing methodology, rates, terms, or conditions of service subject to the jurisdiction of FERC and applicable to a class of customers who are similarly situated with respect to the nature or type of service offered under the tariff.

3.17 **Incremental Additions** - Additions, improvements or capital betterments (including interconnection facilities) to a Member's/Members' electric transmission system reasonably required for the purpose of increasing transmission capacity to accommodate a transmission service request of another Member.

3.18 **Indispensable Intervenor** - Defined in Section 10.8.2.

3.19 **Initiating Party** - Defined in Section 10.6.2.

3.20 **Interruptible Transmission Service** - Transmission service that is subject to interruption by the Transmission Provider with or without prior notice for any reason whatsoever at the Transmission Provider's sole and absolute discretion.

3.21 **Joint Statement** - Defined in Section 10.8.4.

3.22 **Long Term Transmission Plan** - Each Member's transmission plan described in Section 4.7.4 and as specified in the applicable Exhibit A attached to these Bylaws.

3.23 **Mailing List** - Defined in Section 10.6.1.

3.24 **Member** - An entity which has executed these Bylaws and identified as such in Appendix B hereto.

3.25 **NERC** - North American Electric Reliability Council.

3.26 **Notice** - Defined in Section 10.6.2.

3.27 **Ownership-Like Rights** - Rights, benefits and obligations of a Transmission Requester in connection with transmission service associated with Incremental Additions financed through CIAC as provided in Sections 5.4.3, 5.4.4 and 5.4.5.

3.28 **Panel** - Defined in Section 10.6.3.

3.29 **Panel's Statement of Issues** - Defined in Section 10.8.4.

3.30 **Party** - Defined in Section 10.8.2.

3.31 **PFC** - Payments (or other consideration) For Construction made to the Transmission Provider for the construction of Incremental Additions.

3.32 **Planned Native Load** - The Member's forecast load (including the load of retail customers, full requirements wholesale customers and partial requirements wholesale customers) as approved and adopted through the most recent state public utility commission, state energy

2.7 FPA: The Federal Power Act, as it may be amended from time to time.

2.8 Incremental Facilities: Those transmission facilities installed by a Transmitting Member to satisfy a request for transmission service from a Requesting Member that are in addition to facilities planned and built for the Transmitting Member's Native Load.

2.9 Interconnected Transmission System: That portion of each Member's transmission system utilized for bulk power transactions, generally at voltages of 115 kV and higher.

2.10 Interested Parties: Entities such as state and federal land commissions, forest services, wildlife departments, and parks departments, and environmental interest groups, etc. which have an interest in the outcome of transmission planning activities coordinated by SWRTA.

2.11 Member: Any entity which is entitled to apply to FERC for an order requiring transmission services pursuant to Section 211 of the FPA or which would be subject to such an order, or any entity that is located outside the United States that would be entitled to apply for or would be subject to such an order were it located within the United States which signs these Bylaws and is accepted for membership by the Board pursuant to Section 14.3 hereof. No entity may hold more than one (1) membership in SWRTA.

2.12 Member Classes:

2.12.1 Class 1: Members whose primary transmission interests align with "transmitting utilities", as defined under Section (3)(23) of the FPA.

2.12.2 Class 2: Members whose primary transmission interests align with transmission dependent electric utilities.

2.12.3 Class 3: Members whose primary transmission interests align with nonutility suppliers of electric energy for sale for resale.

2.11 FPA. The Federal Power Act as it may be amended from time to time.

2.12 Incremental Facilities. Transmission facilities, other than Existing Facilities, that are reasonably required to satisfy a request for transmission service from a Transmission User.

2.13 Interconnected Transmission System. That portion of each Transmission Provider's transmission system utilized for bulk power transactions, generally at voltages of 100 kV and higher.

2.14 Interconnection. Incremental Facilities other than additions or replacements to existing facilities which:

(i) Connect one system to another system where the facilities emerge from one and only one substation of each of the two systems and are functionally separate from the Transmission Provider's integrated network such that the facilities are, or can be, operated and planned as a single facility; or

(ii) Are identified as radial transmission line(s) pursuant to contract; or

(iii) Interconnect a Transmission User's generation resource at a single point on the Transmission Provider's system, provided that, such interconnection does not interrupt the continuity of the Transmission Provider's system.

2.15 Member. Any signatory to this Governing Agreement which is a Transmission Provider, a Transmission User or a Commission operating or located in the Western Interconnection.

3.4 **Binding Arbitration Procedure** - The procedures for binding arbitration set forth in Sections 10.6 through Section 10.12 of these Bylaws.

3.5 **Binding Arbitration Proceeding** - An application of the Binding Arbitration Procedure to a particular dispute between or among Members.

3.6 **Board of Directors or Board** - The Board of Directors established pursuant to Section 8 of these Bylaws.

3.7 **CIAC** - Capital contributions In Aid of Construction is an advance of money or other consideration paid to a Transmission Provider for the construction of Incremental Additions.

3.8 **Collaborative Discussion** - An informal process intended to facilitate discussion and resolution of disputed issues under these Bylaws by senior management representatives of the Members involved in the dispute.

3.9 **Consistent Application or Consistently Applied** - Past, current and proposed interpretation and application by a Transmission Provider of NERC, WSCC and the Transmission Provider's reliability criteria, standards, operating procedures and guidelines and the Transmission Provider's planning assumptions, processes and methods (each referred to for purposes of this definition as a "Requirement"), as the case may be, in relationship to (i) such Transmission Provider's interpretation or application of a Requirement for its use of its own system and (ii) such Transmission Provider's interpretation and application of a Requirement for a third party's use (including a Member's or Members' use) of the Transmission Provider's system, so as to prevent a Transmission Provider from interpreting or applying a Requirement in an inconsistent, arbitrary, capricious or discriminatory manner.

3.10 **Dispute Resolution Procedure** - The procedures set forth in Section 10 of these Bylaws for resolving disputes between and among Members.

3.11 **Dispute Resolution Proceeding** - An application of the Dispute Resolution Procedure to a particular dispute between or among Members.

3.12 **FERC** - The Federal Energy Regulatory Commission or its regulatory successor.

3.13 **FERC Determination Matter** - Any matter subject to FERC jurisdiction where (i) FERC policy does not exist or is not sufficiently developed or articulated to permit the panel to render a decision regarding such matter, or (ii) the matter is the subject of a current FERC proceeding or policy-setting process addressing new FERC precedent or policy, or (iii) all proposed resolutions in a Baseball Arbitration or any applicable resolution in a Regular Arbitration regarding such matter are fundamentally different from any resolution of such a matter theretofore approved by FERC in a currently-applicable rule or precedential determination respecting the same or similar service, so that there are no usable standards to apply in rendering a decision consistent with Section 10.10.6.

2.3 Board: SWRTA's Board of Directors, as described in Section 13 below.

2.4 Commission: A state or provincial utility regulatory commission or energy commission.

2.5 Existing Facilities: Those transmission facilities that are in the Member's plant accounts as plant-in-service at the time the initial request for transmission service is made.

2.6 FERC: The Federal Energy Regulatory Commission or its regulatory successor.

2.5 Board. The Association's Board of Directors, as described in Section 5.

2.6 Commissions. State or provincial utility regulatory commissions or energy commissions.

2.7 Committee. A Committee of Members established pursuant to this Governing Agreement or by the Board.

2.8 Coordinated Planning. The activities described in Subsection 9.3.

2.9 Existing Facilities. Those transmission facilities owned by a Member, or transmission capacity under contract to a Member, previously used to transmit electric energy.

2.10 FERC. The Federal Energy Regulatory Commission or a successor agency.

DEFINITIONS

WATSCO

3. DEFINITIONS: The following capitalized terms, whether in the singular or the plural (unless specifically provided otherwise), when used in the text of these Bylaws shall have the respective meanings set forth or provided for in this Section 3:

3.1 Applicant - An entity listed in Appendix B which executed the Bylaws prior to the Bylaws being filed with FERC.

3.2 Available Transmission Capacity - With respect to that period of time for which a Transmission Requester has requested transmission service, that amount of transmission capacity on the appropriate and/or affected portion of a Transmission Provider's transmission system (including entitlements) which is not needed to accommodate:

(i) The Transmission Provider's Planned Native Load requirements;

(ii) Existing commitments for Firm Transmission Service contracts including those for full or partial requirements customers;

(iii) The Planned Native Load requirements, if the Transmission Provider maintains a control area, of all Members located within the Transmission Provider's control area, but only to the extent that (a) these Members are or will be dependent upon said Transmission Provider for transmission service consistent with Transmission Provider's contractual and/or regulatory obligation to provide transmission service, and (b) to the extent not included in Section 3.2(i) and (ii) above;

(iv) Transmission capacity of the Transmission Provider which is temporarily committed for a competitive resource acquisition process as provided in the applicable Appendix A, until such process has progressed to a stage where it is reasonably certain that such capacity will not be utilized with respect to the subject resource acquisition; and

(v) Transmission Provider's Prudent Reserve.

As used in this Section 3.2, "Planned Native Load requirements" with respect to intertie lines or other Radial Transmission Facilities shall include only such transmission capacity (i) specified by duration of service, transfer capability required, the point of receipt and the point of delivery, and (ii) included in the transmission plans required in Section 4.7.

Notwithstanding the provisions of this Section 3.2, transmission capacity specified under Section 3.2(i), (iii), (iv) and (v) shall be deemed Available Transmission Capacity with respect to requests for Interruptible Transmission Service under these Bylaws.

3.3 Baseball Arbitration - Defined in Section 10.8.3.

SWRTA

2. DEFINITIONS:

The following terms, when used herein with initial capitalization, whether in the singular or the plural, shall have the meanings specified:

2.1 Arbitrator: An individual selected to resolve disputes arising under these Bylaws pursuant to Section 7 hereof.

2.2 Available Transmission Capacity: That amount of transmission capacity available to a Transmitting Member to provide transmission service to a Requesting Member which is not needed to accommodate the Transmitting Member's: (i) Native Load over a ten (10) year planning horizon; (ii) existing commitments for wholesale transmission and electric service contracts; (iii) reasonable reliability requirements as determined by the reliability criteria of the Transmitting Member, consistent with Prudent Utility Practice and the appropriate regional reliability council criteria, which requirements shall be impartially applied without undue discrimination; and (iv) unscheduled flows, pursuant to the procedure defined by WSCC.

WRTA

2. DEFINITIONS.

When capitalized herein, whether in singular or plural, the following terms shall have the following meaning:

2.1 Arbitrator. An individual selected to resolve disputes arising under this Governing Agreement pursuant to Section 12.

2.2 Arbitration Committee. The Committee described in Subsection 6.7.

2.3 Available Transmission Capacity. That amount of transmission capacity available to a Transmission Provider which is not reasonably required to accommodate the Transmission Provider's: (i) Native Load; (ii) existing contractual commitments for firm wholesale sales; (iii) existing contractual and statutory commitments for firm transmission service; (iv) Prudent Reserve and (v) pending good-faith requests for transmission services.

2.4 Award. A decision of an Arbitrator made pursuant to Subsection 12.3 of this Governing Agreement.

DEFINITIONS

1.6 **Pricing Principles** - To the extent consistent with the FPA, FERC regulations, policies and precedents and these Bylaws, the pricing of transmission services provided pursuant to contracts entered into in accordance with these Bylaws shall be cost-based and shall not be at the expense of the investors in, or customers or owners of, the Member providing such services.

1.7 **Membership** - To maximize the effectiveness of WATSCO, membership in WATSCO will be open to any entity that is subject to, or eligible to apply for, an order under Section 211 of the FPA.

1.8 **File Bylaws with FERC** - The Applicants intend to file these Bylaws with FERC in accordance with the provisions of these Bylaws.

1.9 **Individual Contracts** - The Members intend to enter into separate contracts for the provision of transmission service consistent with these Bylaws.

WATSCO

BYLAWS OF THE
WESTERN ASSOCIATION FOR TRANSMISSION SYSTEMS COORDINATION

1. PREAMBLE: These Bylaws, which include exhibits and appendices attached hereto, of the Western Association for Transmission Systems Coordination ("WATSCO") are made with reference to the following facts among others:

1.1 Scarcity of Electric Transmission Resources - Electric transmission capacity is a scarce and valuable resource which is imbued with the public interest. Often, the construction of transmission facilities and the acquisition of transmission corridors utilize valuable public lands and/or involve the taking of valuable private property through the power of eminent domain by publicly or privately owned utilities. Use of this scarce resource should therefore be in a manner which promotes the broadest public benefit and the efficient use and expansion of the Members' transmission systems, and should not be used to collect monopoly rents.

1.2 Societal Benefits - Efficient use of existing and future transmission facilities on a fair, non-discriminatory basis can yield many societal benefits that include:

- enhanced economic efficiency;
- increased competition in the electric power market;
- better protection of the environment;
- better use of transmission corridors; and
- lower electricity rates for all consumers.

These benefits can best be realized through a voluntary organization involving electric utilities, non-utility generators and regulatory agencies.

1.3 Purpose of WATSCO - WATSCO is formed expressly for the purpose of facilitating the efficient use of existing and future transmission facilities and the coordinated planning for expansion of the transmission system on a regional basis without impairing service to Members' Planned Native Load or unreasonably impairing the continued reliability (based upon consistently applied NERC, WSCC and an affected Member's reliability criteria and guidelines) of any Member's electric system. Use of transmission facilities by Members in accordance with these Bylaws includes long-distance bulk transmission service, transmission service within and between control areas for wholesale utility customers and non-utility generators, and all other services available under Sections 210, 211 and 212 of the Federal Power Act.

1.4 Regional Transmission Planning - Members recognize the need for region-wide coordinated planning of transmission facilities to assure the most efficient development and expansion of the transmission system to serve the needs of all consumers and power providers with a minimum of adverse environmental impacts. Transmission planning should be coordinated on a regional basis to meet the transmission service needs of all Members. Coordinated planning will ensure the efficient use of existing transmission facilities, reducing the need for new transmission facilities, thereby minimizing environmental impacts. Such planning will assure the most efficient development and expansion of the transmission system.

1.5 Transmission Capacity - In order to ensure that adequate transmission capacity exists to meet all Members needs, Members must increase transmission capacity when necessary to accommodate transmission requests from other Members in accordance with these Bylaws.

PREAMBLE

SWRTA 1/21/94

BYLAWS

SOUTHWEST REGIONAL TRANSMISSION ASSOCIATION

PREAMBLE

The Southwest Regional Transmission Association (SWRTA) is a regional transmission group (RTG), as defined by the Federal Energy Regulatory Commission (FERC) in its Policy Statement Regarding Regional Transmission Groups, issued July 30, 1993, Docket No. RM93-3-000 (RTG Policy Statement), formed to facilitate the optimal use of existing transmission facilities and the coordination of planning and construction of transmission system expansions on a regional basis. Pursuant to the Energy Policy Act of 1992, FERC's RTG Policy Statement and these Bylaws, SWRTA Members agree to promote coordinated transmission planning, efficient use of transmission capacity, nondiscriminatory access to transmission facilities and fair pricing for transmission services.

1. PURPOSE:

SWRTA is a voluntary RTG comprised of bulk transmission owners, operators and users with an interest in transmission in the western United States. Members have formed SWRTA to foster the efficient, equitable and reliable use of existing and future bulk transmission facilities, thus facilitating access to generation markets. It is anticipated that SWRTA membership will facilitate: (i) opportunities for Members to utilize existing and future bulk transmission facilities for transmission service, (ii) coordination of future additions to the bulk Interconnected Transmission System to promote system reliability and efficiency, (iii) coordination of the acquisition of transmission rights-of-way, licensing, and siting for transmission lines on a regional basis, and (iv) integration of Members' decisions regarding construction of future generation resources with regional plans for transmission development, load reduction potentials and regional environmental considerations.

WRTA 2/01/94

PREAMBLE

This Western Regional Transmission Association (Association), is intended to facilitate the efficient use of existing transmission facilities, coordinate the planning of transmission system expansions and expedite the resolution of disputes concerning transmission.

Pursuant to this Governing Agreement, Members agree to promote coordinated transmission planning, efficient use of transmission capacity, nondiscriminatory access to transmission facilities, competition in generation markets and reasonable terms, conditions and pricing for transmission services.

1. PURPOSE.

The Association is a voluntary organization of Transmission Providers, Transmission Users and Commissions located throughout the Western Interconnection. Members have formed the Association to foster the efficient, equitable and reliable use of existing and future transmission facilities and the expeditious and fair resolution of disputes related to transmission access. The Association shall provide a forum for coordination of transmission planning and for the exchange of information to assist Members in meeting their transmission needs. To the extent practicable, the Association shall pursue the activities contemplated hereunder in a manner that avoids duplicating the activities of other transmission planning organizations such as the WSCC and Subregional Coordination Groups. To that end, the Association intends to investigate the potential for the consolidation of some or all of the functions provided for in this Governing Agreement with those of the WSCC with the understanding that any such consolidation would require the amendment of this Governing Agreement in accordance with Section 15.

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PREAMBLE