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CONTRACTS FOR DISPATCHABLE POWER:
ECONOMIC IMPLICATIONS FOR THE COMPETITIVE BIDDING MARKET

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Executive Summary

Competitive bidding for electric power is maturing. Increas`ng numbers of utilities are soliciting proposals from private suppliers. The amount of capacity being sought is increasing, and potential suppliers appear to be abundant. Analysis of these developments still remains limited. Evidence on the behavior of this market is scarce and sketchy. The underlying economic principles that are shaping the market have not clearly been articulated.

In this report we examine the economics of competitive bidding both empirically and analytically. Previous study of this market has focused on the evaluation criteria specified in Requests for Proposals (RFPs), and highly aggregated summary statistics on participation and results. We continue the examination of RFPs, but also survey the details of long term contracts that have emerged from competitive bidding. Contracts provide a new level of specific detail that has not been previously available.

State of the Market

Survey of RFPs

The principal theme which emerges from the survey of RFPs is the importance of dispatchability. Utilities are insisting upon operational flexibility from private suppliers. They want to be able to dispatch these resources in much the same way as they operate their own plants. This contrasts with PURPA implementation based on inflexible "must take" provisions. The real time nature of the electricity market is inconsistent with relying, to any large extent, upon suppliers who cannot accommodate dispatching.

The RFPs also show other adaptations of utility planning to an environment of increasing competition. The evaluation systems embodied in the recent RFPs are deliberately inexplicit. Utilities are increasingly unwilling to indicate their detailed evaluation criteria in the form of self-scoring work-sheets that bidders fill out as their bid. This deliberate imprecision is a sign that there is abundant competition. There are so many potential suppliers that utilities do not need to bind their RFPs to a rigid, public, pre-specified system of evaluation criteria weights. As a general guide to their needs, however, utilities often disclose their broad planning objectives, and even details on alternative resources and their costs.

Transmission issues are another area where the private power market is maturing. The RFPs make clear whether the utility will assist bidders who need to obtain wheeling, or whether that obligation is placed solely on the potential seller. Transmission impacts are being recognized in a number of ways that were previously ignored or left ambiguous. Area-specific transmission loss adjustments are being incorporated into bid evaluation, or even proposal-specific load flow studies are being performed.

Contract Features

Contracts are not easy to get, but we did collect a number of them for market analysis. Contracts show both the ingenuity of sellers and the complexity of projects. Although all the projects reviewed here are dispatchable in some fashion, there are clear differences in the extent of flexibility that will be available in practice. A number of the contracts represent projects that are clearly intended to be baseload, high capacity factor producers. These include two gas-fired combined cycle projects located in New England with unique pricing structures. Both of these (Enron and Dartmouth) have "unbundled" gas contracts with low commodity costs and high fixed transportation demand charges. In one case that gas will come from Alberta, Canada and in the other it will be imported LNG. This results in a split of fixed and variable costs that resembles traditional baseload power pricing. Therefore the need for economic curtailment of output in these cases will be minimal.

Two other contracts involve projects that allow the purchasing utility to turn the units on or off (i.e. "commitment"), but limit the operating range to between 80% and 100% of rated capacity. The origin of these operating restrictions is quite different in each case. The gas-fired combined cycle Doswell project appears to require this restriction due to an inflexible clause in its pricing agreement. Variable energy costs will be paid on the basis of a contract heat rate times an indexed cost of gas. The contract heat rate does not recover cost when the unit is operating below 50% of capacity. Combined cycle plants have a very big range of efficiency between minimum operating level and full output. Since the Doswell contract heat rate did not account for this variation, the operating restriction is necessary from the seller's viewpoint.

The Vista/Paulsboro projects have the same restrictions as Doswell, but for somewhat different reasons. Vista/Paulsboro are coal-fired units selling 60% of their capacity to one utility. The limited curtailment in their case appears due more to engineering restrictions on minimum performance of the unit than to pricing inflexibilities. These projects must seek alternative buyers for their incremental capacity. Actual dispatch of the unit will probably require a priority ordering for purchase between the ultimate buyers. These projects represent a new product structure in the market; what are called "merchant IPPs." The developer achieves scale economies, even in the face of project size restrictions from a single buyer. Selling the incremental capacity from a merchant IPP may require transmission access.

Other contracts include a case where output is explicitly allocated on a priority basis across three separate markets (TECO Power Services), a peaking project with restrictions on annual start-ups and operating hours (Commonwealth Atlantic), and a coal- fired project designed to serve intermediate rather than base loads (Multitrade).

Finally, the contracts sometimes contain security requirements which require the project to provide financially for contingencies that might have negative impacts on the buyers.

Key Findings from Economic Analysis

The various dispatchability requirements identified in the contracts impose new problems for economic analysis. Most of the conditions that appear important contractually have not been previously examined in a systematic fashion. Methods for evaluating the price impacts of dispatchable projects are still not well understood. Other contractual issues, such as security clauses, remain controversial. We examine these issues and propose potential improvements in current practice.

Ratio and Difference Scoring

Many bid evaluation systems use a "percentage of avoided cost" criteria to rank price offers. We find that these ratios are inaccurate measures of value for dispatchable projects. They do not account for value differences that are reflected in how long it is economic to operate one project rather than another. Even in sophisticated price scoring systems, such as the one incorporated in the 1989 Jersey Central Power and Light RFP, failure to account for operating duration will mis-measure value. Even though the JCPL system does assign different avoided cost streams to bids whose optimal operating durations differ, once the value is reduced to a ratio, a scoring bias results. The bias works against base load projects. We show in detail that if two bids have the same ratio score, i.e. percentage of avoided cost, the one which is dispatched for more hours, i.e. is more baseloaded, saves more money and should be preferred.

We illustrate this point with a simple model of avoided cost for dispatchable bids, and by using the spreadsheet developed by JCPL for use by bidders in their 1989 RFP.

Minimum Operating Levels

The operating restrictions identified in the contracts can only be valued with highly complex computer models. The models usually used for life-cycle cost estimation, even when dispatch is represented with some sophistication, cannot detect some of these economic effects. We found that the most important of these effects was high minimum operating levels, as in the Doswell and Vista/Paulsboro contracts. Using a detailed chronological production simulation model, we conclude that this restriction imposes cost penalties on bids of this kind. On a levelized life- cycle basis, we estimate that the 80% minimum operating level restriction raises the cost of a gas-fired intermediate load project like Doswell by approximately 10%. With high gas prices the impact can be twice as large The corresponding estimate for coal-fired baseloaded projects like Vista/Paulsboro is about 5%. These effects are large enough to eliminate the benefits of intermediate load projects. Because the benefits of baseload projects are typically larger, the extra costs due to high minimum operating capacity would not have so severe an effect.

We recommend that utilities evaluating competitive bids should examine operating restrictions carefully using detailed chronological simulation. The results of these tests should be incorporated into the broader screening models used to estimate lifecycle benefits. If there are low cost remedies to the minimum load problem on particular power systems, then the problem identified here can be reduced.

Security Requirements

Many of the contracts contain clauses that require suppliers to post security to cover contingencies which could have negative impact for the utility. In some cases, these security requirements are directly related to front loading of payments. There is ambiguity about the origin of front loading, which involves payments above estimated avoided costs. When avoided costs included the capital associated with deferred utility plants, front loading measures depend upon the rental rate theory of capital recovery. We show what this theory asserts, and how to calculate the rental rate in particular cases.

Security requirements can be met in a number of ways. Performance insurance is one of the newer products available to meet these requirements. This insurance appears to cost considerably less than alternatives. We use an example to compute its relative cost and examine whether it is a substitute for other forms of security. The insurer must retain the right to cancel these policies as a means of controlling the project operator's behavior. The right to cancel makes this insurance a weak instrument in the bid evaluation stage. Merely asserting that you will obtain performance insurance is not a strong guarantee. Once contracts are in place, however, performance insurance may well lower the cost of security. This is accomplished by risk sharing across a pool of projects, and the superior technical knowledge of the insurer.

Research and Development Implications

The minimum load problem arises at the level of the entire power system. Therefore solutions should be sought on a broad basis. New technologies may have operating inflexibilities that are difficult to reduce compared to retrofits of existing units. Therefore the research portfolio could usefully address techniques to reduce the minimum operating levels of existing units. These may be relatively low in cost, and have substantial benefits beyond their direct effects.

Conclusion

Competitive bidding systems are developing into a more complete resource acquisition process by incorporating dispatchability requirements. There are still difficulties evaluating operating features proposed by bidders. It remains to be seen how well the complex long term contracts governing these transactions will work in practice. Nonetheless, bidders are showing a degree of ingenuity and flexibility that is a significant step beyond PURPA must-take implementation.

1. RECENT DEVELOPMENTS IN COMPETITIVE BIDDING

1.0 Overview

New evidence on the nature of competitive bidding for electric power generation comes both from the RFPs issued by utilities and the power purchase contracts which are ultimately negotiated. The RFPs reviewed here show that there is abundant competition. Fewer utilities currently feel obliged to reveal explicitly their bid evaluation criteria than in the recent past. Increasing emphasis is being placed on "dispatchability." Utilities want bidders to provide operational flexibility, defined in various ways. Transmission issues are also coming to the foreground. Some RFPs require bidders who need wheeling to have such contracts in advance of bidding. In other cases, the utility offers to faciltate third-party transmission. There are even cases where bidders must perform detail transmission studies as part of the bid.

Power purchase contracts resulting from competitive bidding are now becoming public, either through FERC filings or from state commissions. These contracts show a wide variety of non-traditional pricing, and a spectrum of operating features. Minimum operating level is a key issue in these contracts. To avoid the costs and inflexibilities of PURPA "must-take" conditions, units should be curtailable. Contracts show considerable variation on how much output can be reduced when needed. Some of the rigidity reflects poor specification of pricing rules. In other cases, rigidity results from projects seeking multiple customers. Contracts are a crucial new form of data on the nature of the electricity market, because they define both current prices and the distribution of risk- bearing.

1.1. Design of Bidding Systems: A Survey of RFPs

1.1.1 Introduction

This section describes innovations and trends in the design of competitive bidding systems for electric power by surveying recent RFPs. The discussion follows from previous analyses of this market as of approximately June, 1989 (see Kahn, et. al., 1989). In our previous work, we distinguished between bid evaluation systems in which bidders self-scored their proposals using explicit criteria defined by the RFP, and those systems where the criteria were not explicit. We used the term "open" to describe the former type, and "closed" to describe the latter.

We observe two distinct trends in the bidding systems reviewed here. First, there is a pronounced shift toward the closed systems. For whatever reason, most of the schemes reviewed here avoid the explicit definition of evaluation criteria. Within this general framework, however, a second trend is becoming apparent, namely explicit linkage of bidding with the utility's resource planning process. In the five closed bidding systems reviewed here, all the utilities provide background planning data on their own alternatives. These resource planning documents give general guidance to bidders about the character of the utility's specific needs, and the costs of its own alternatives.

One particularly important area where utility policy toward bidding programs is becoming clarified involves transmission and wheeling issues. There is an increasing recognition that these issues can be vital to the success of individual projects and even of entire bidding programs. Nonetheless, not all utilities are willing to become actively involved with potential suppliers in acquiring resources located outside of the utility's control area. The current round of utility RFPs indicates, more clearly than in the past, whether the buyer will undertake the obligation to secure out-of-control area transmission, or whether this responsibility falls on the bidder. Even in the case where the utility will not assume responsibility for transmission, methods are being developed to assess transmission impacts associated with competitive bidding more completely (Shirmohammadi and Thomas, 1990).

This section complements a recent survey of bidding conducted by the National Independent Energy Producers (NIEP), a trade association of firms engaged in the private power business (Wellford and Robertson, 1990). The NIEP survey is the most comprehensive review of the raw data on RFPs and responses throughout the U.S. Further, the NIEP survey emphasizes features of the bidding process which are of particular interest to its constituency. Private producers commonly express concern that the market power of regulated utilities will be used prejudicially against the interests of unregulated suppliers. The NIEP report focuses on potential cross-subsidies between the regulated firm and its un-regulated affiliates, ambiguities concerning transmission access and pricing, and potential asymmetries in regulatory treatment of utility projects compared to private power.

In this section we focus more narrowly and intensively on the structure of particular solicitations. Although bidding is becoming very widespread, it is still a very new phenomenon with many unsettled features. Only by careful examination of bidding programs in detail can we identify best practices and constructive innovation. It is also important to identify blind alleys. We review six significant utility solicitations for power below. These were selected either because the amount of power being requested is large, or the approach taken is particularly unique. For each case we identify major requirements of the solicitation as well as important individual aspects of the utility's approach.

1.1.2 Virginia Power

Virginia Power (VP) issued an RFP on August 15, 1989 for 1100 MW of base or intermediate generation to be delivered in the 1995-1997 time period (VP, 1989). This contract emerged from negotiation rather than competitive bidding. The RFP broadly resembles the VP 1988 solicitation, which was the first major solicitation based on a closed evaluation system. The principal difference in the 1989 solicitation is that many threshold criteria and proposed contract terms are expressed more explicitly. The most important threshold criteria include the following:

1. Projects proposed for sites out of the VP control area must have wheeling contracts that VP approves.
2. All capacity located in the VP control area must be dispatchable. VP states that it prefers that the minimum operating level on baseload/intermediate capacity not exceed 25% of maximum output.

Contract conditions specify the form of payments and obligations of suppliers. Among the most important of these are:

1. Indexation of fuel costs to VP opportunity costs. The form of fuel cost adjustment is an indexation of the project's proposed base price which reflects the costs facing the utility for its own facilities.
2. Bidders must specify their entire fuel-input/power-output profile. This allows the utility to evaluate their operation over the whole range of operating levels.
3. All fixed costs of the project must be included in the capacity price bid. In particular, this includes gas transportation demand charges for projects using natural gas. The purpose of

this requirement is to insure economic dispatch of resources, and to prevent potential financial problems for facilities that might not recover fixed costs that were embedded in the variable price.

4. Bidders may offer levelized capacity prices, just as long as the present-value of these payments in the first 15 years of the contract does not exceed 90% of total present value. The last ten years of prices can also be levelized.
5. Capacity payment penalties for dispatch deviations greater than 5%. The power purchase contract gives an explicit schedule of penalties to be applied monthly for incidents during which the supplier deviates from the dispatch instructions given by the utility. This represents the most well-defined performance criteria for dispatchable projects in any bidding program to date.

VP announces that the RFP is designed to elicit bids that will be good enough to alter its projected expansion plan for the 1995-1997 period, which is based exclusively on combustion turbines. The utility reserves the right to reject all bids and construct its own facilities. The RFP is timed to meet the lead time requirements of base or intermediate capacity. Because peaking facilities do not require this lead time, VP may reject all bids of this kind.

Specifying the economic competition between baseload or intermediate resources and a peaking alternative is not a trivial problem. Simple price scoring techniques such as busbar cost comparisons fail to capture the fundamental dispatch differences which are at the heart of the problem. Optimization methods are the most general approach to this problem.

1.1.3 Jersey Central Power and Light

An RFP for [illegible]70 MW was issued during the summer of 1989, providing for both demand and supply side bids. There were eleven responses on the supply side for a total of 712 MW. Four of these were selected as winners in December, 1989; two 100 MW coal burning projects to be sited in New Jersey, and two 17 MW wood fueled projects.

The evaluation criteria followed the New Jersey Stipulation of Settlement (1988) in broad outline, with a few characteristic modifications. The Non-Economic Factor component of the scoring system (nominal weight of 20%) emphasized dispatchability features. Curtailment options were weighted 4% and nature of control 4%. The principal innovations in the Project Status Factor category (nominal weight of 25%) were 4% weight given to secure fuel supply and a negative weighting of up to 8% for projects in excess of 130 MW. These negative weights for projects over 100 MW effectively capped the size of projects at that level.

Price Scoring Procedure

Jersey Central Power and Light (JCPL) proposed a very complex energy price evaluation scheme that attempted to capture the economic dispatch effects for projects selecting this option. Because of the strong weighting given to these features in the Non-Economic Factor, JCPL anticipated receiving many bids of this kind. Apparently all bidders offered this option. The energy price evaluation scheme consists of two curves, one representing the avoided energy cost duration and one representing the energy bid price duration. The basic idea is that a bidder will offer an energy price and then use these curves to determine both how long a project would operate at that price and what the avoided cost would be corresponding to that price. The process is computationally complex because JCPL has a different set of curves for off-peak and on-peak periods for each year of a twenty year forecast, and three different scenarios over which the price scoring is performed.

The underlying methodology behind this approach requires some explanation. Both the avoided cost and bid price duration curves are marginal cost duration curves (see Bloom, 1984), but they are based on different plans The avoided cost duration curve is ba ed on the JCPL supply plan in the absence of the private suppliers. This plan consists primarily of combustion tu bines in the short run and a combined cycle plant in the longer run. In the later years of the plan the avoided cost curve is essentially capped by the combined cycle energy cost in the on-peak period and most of the off-peak period. The bid price duration curve reflects a supply plan including non-utility generation, deferring the combustion turbines until 1996 and eliminating the combined cycle plant completely.

Two further aspects of the price scoring involve capacity payments and start up costs. Details of these additional terms are explained below The overall price structure of a bid has the following form:

Bid = Energy Price*Expected Output + Capacity Price + Start-up Cost*Expected Starts. (1-1)

The RFP gives bidders instructions on how to compute the two expected values, and no freedom in this regard. Upper bounds are given on avoided energy and capacity prices. For each bid Equation (1-1) gives a total dollar cost which is then compared on a present-value basis to avoided cost. The price score of a bid is determined by the ratio of these; that is

Price Score = Constant*(Bid/Avoided Cost). (1-2)

The constant in Equation (1-2) is determined so that bids receive 0.75 points for every 1% below avoided cost, up to a maximum of 50 points for a bid that was 25% of avoided cost. The total effect of Equations (1-1) and (1-2) can only be understood by some account of the capacity price and start-up cost terms.

The capacity payments are based on the deferral of combustion turbines. The pattern of these costs varies over the low growth, median growth and high growth scenarios, but is generally in the range of $60-80/kW-yr on a twenty year levelized basis. Capacity bids may not exceed the present-value of the ceiling level specified in the RFP.

If the bidders wish to receive payments for their start-up costs, the RFP prescribes a procedure for evaluating their cost in the bid. This consists essentially of specifying an estimated number of start-ups for any project depending on its estimated capacity factor. The bidder then gives a price per start-up and the total cost is the product of this price times the estimated number of events. The bidder has no choice about the number of estimated starts. The RFP locks him into a number that is the result of his estimated capacity factor. For low capacity factor bids this number can be quite high. If a plant is expected to operate between 10 and 35% of all hours, for example, then the RFP specifies 260 start-ups per year (essentially every weekday). The estimated number of starts declines for capacity factors below 10% and above 35%. In the former case it is because the plant will be used fewer days. In the latter case it is because there will be fewer shutdowns.

Bidders need not ask for explicit start-up payments. As an alternative they can merely fold these costs into their energy price bid. The RFP tends to encourage such a strategy by giving estimates for the number of starts that appear quite high.

We examine the economic implications of this approach in more detail below.

1.1.4 Florida Power and Light

An RFP for 800 MW of capacity was issued in July, 1989 for delivery in the 1994-1997 interval. The power from this RFP will compete against the proposed two unit coal gasification combined cycle plants projected for 1996 at the Martin site. The RFP specifies threshold requirements for bids which include (1) licensing, permitting and construction plans, (2) compliance with Florida Electrical Power Plant Siting Act, and (3) capability to burn coal or alternate fuel.

Contract Description

1. Pricing terms: fixed capacity payments, indexed energy and O&M payments.
2. Completion security: $30,000/MW deposited with Florida Power and Light (FPL) to insure completion of project by proposed Acceptance date. Paid as liquidated damages to FPL at 10%/month starting two months after Acceptance date if delayed.
3. Operating security: negotiated sum in the form of performance bond or letter of credit.
4. Right of First Refusal: if ownership transfer is proposed
5. Dispatchability: not required in bid
6. Termination charges: payable by FPL if for its own convenience the utility wishes to end the agreement. Termination for cause provisions also required.
7. Force majeure: can trigger termination if a single event causes non-performance for longer than 180 days, or a sum of events lasts longer than 360 days.

Evaluation Criteria

FPL does not disclose detailed procedures for evaluating bids, but does give extensive background on its own internal planning approach and the results of its studies (FPL, 1989b). These are contained in FPL's Petition to Determine Need filed with the Florida Public Service Commission and accompanying the RFP (FPL, 1989a). The methods and assumptions used for FPL resource planning will also be used to evaluate bids.

Quantitative estimates of particular FPL projected costs are documented to a limited extent in their Petition to Determine Need. Most detail in that document is given for fuel cost forecasts. The costs of the Integrated Gasification Combined Cycle (IGCC) units at Martin are also given in summary form. Power purchase contract costs are also given. The Petition to Determine Need is relatively clear about price factors used for resource planning, but less clear about non-price factors. The RFP lists a wide range of evaluation criteria that will be applied to bids. These are listed below.

1. Price: system simulation methods used with and without proposed project including adjustment for transmission.
2. Location: effects beyond those included in price calculation (i.e. losses) will be added.
3. Schedule flexibility.
4. Fuel diversity and price risks.
5. Security of fuel supply: ownership or contractual control of fuel, enforceability of fuel supplier commitments, transport agreements, price stability of fuel and transport contracts, potential competition among these suppliers.
6. Dispatchability: PROMOD input variable values. Automatic Generation Control (AGC) desirable for projects greater than 75 MW.

7. Reactive Power: units with high power factor capability preferred.
8. Contract term: long term (ten year minimum) preferred up to comparable lifetime of IGCC.
9. Maintenance scheduling: co-ordination with FPL preferable.
10. Completion security: provisions greater than minimum requirement are preferred.
11. Front-loading security: not required, but FPL will assess the amount by which payment exceeds value. Bidders may propose some risk mitigation.
12. Financial Viability: FPL requests financial data to estimate project equity over the contract duration. More equity means less operating risk.
13. Long term plant performance plan: bidders can show evidence of design considerations, an O&M reserve fund, or O&M plan.
14. Developer experience.
15. Level of development: related to minimum threshold requirements.
16. Local benefits.

Supplemental Information Document (FPL, 1990) specified in greater detail some of the relevant evaluation criteria. Transmission loss effects, for example, appear significant. FPL reports peak losses from its Northern Florida coal plants of approximately 10%. Capacity payments should be levelized but must also be bid with incentive and penalty rates for performance above and below the target equivalent availability factor. There will be a dead band of 3% around this target, and the penalty rate should, in principle, go to zero output. The energy payment formula also has a provision for sharing savings with FPL of actual fuel costs below the adjusted (i.e. indexed) target value. This sharing factor may be zero, but FPL will favor bids where it is non-zero.

1.1.5 Public Service of Indiana

RFPs issued in December, 1989 solicit supply projects from utilities, non-utility generators or demand side resources to meet a forecast capacity need of 1300 MW in the 1993-2000 time period. Resource planning studies, cited in testimony from a recent rate case, show that optimal capacity expansion over this time period would consist entirely of combustion turbines operating with 10-15% capacity factors (Benning, 1989). This testimony was made available to bidders, but not the underlying studies themselves or any detailed summary of them. The testimony also included data on the cost of twenty year life extension projects at two Public Service of Indiana (PSI) generating stations. At the four unit Gallagher station (140 MW/unit) the costs averaged $160/kW, and at the five unit Wabash River station (4 units at 85 MW and one unit at 95 MW) the costs average $270/kW. These costs do not include scrubbers, which have been estimated to cost between $200 and $240/kW for these units (Indiana State Agency Workgroup, 1989).

The resource planning studies appear to be of the same type as reported by Virginia Power. A long range capacity optimization study is conducted using three generic alternative types of resources, combustion turbines, combined cycle and pulverized coal. The capital costs of these alternatives were assumed to be $375/kW, $435/kW and $1429/kW respectively in 1988 dollars. The results of the study showed that between 1990 and 2003 it was optimal to install ten 130 MW combustion turbines. Combined cycle was added first in 2004 and pulverized coal was added first in 2007.

These planning studies include the effect of a projected off-system sale of 450 MW of base load power (PSI, 1990). This sale is part of PSI proposed market based program for power sales and open access transmission (Rogers, 1990). This program forms the basis for the RFP because it is aimed at re-optimizing the PSI system away from an excessive reliance on baseload capacity and toward a more balanced generation mix with incremental addition of peaking capacity. The transmission provisions are offered in part to reduce any potential market power associated with the bulk power sales (PSI, 1989a). PSI is making sure that any potential customers for its power have access to other sellers through use of the PSI transmission network. This policy also provides the basis for PSI's offer to help provide potential bidders in its RFP with transmission service.

The RFP itself is brief and relatively uninformative (PSI, 1989b). PSI deliberately refers to its approach as a "closed" bid evaluation system and refuses to disclose the weights that will be applied to different factors. The requirements for a bidder's proposal are listed below.

Proposal Requirements

1. Feasibility demonstration: engineering studies including cost estimate.
2. Licenses and permits: demonstration of the ability to procure these.
3. Fuel supply: contract details.
4. Financial capability of sponsor.
5. Construction and operation capability: documentation of plans, schedules and contracts.
6. Price terms: separate firm from secondary energy; wheeling charges separate. PSI evaluation will look at price risk and front loading.
7. Duration: 10 year minimum.
8. Operating characteristics: heat rate and ramp rate.

PSI would not rule out transferring pollution credits under acid rain legislation to private suppliers. However, if the bids consist primarily of peaking capacity, this should be gas-fired and therefore not impact sulfur emissions issues.

Self-generators may offer load displacement.

Bidders retain the responsibility to interconnect with the PSI system. The utility will assist developers proposing projects outside the PSI control area who request help to obtain wheeling.

1.1.6 Sacramento Municipal Utility District

Sacramento Municipal Utility District (SMUD) is facing a major re-orientation of its operating environment and resource mix. In 1990 SMUD will being operating as its own control area (as opposed to previously being integrated into the Pacific Gas & Electric (PG&E) control area). Further, it has had to re-structure its supply mix substantially due to the closure of the Rancho Seco nuclear plant. The resource plan for 1990-1995 relies heavily on firm purchases, most of which need to be replaced in 1996. This sets the stage for SMUD bidding programs.

SMUD issued an RFP on March 15, 1990 (SMUD, 1990). The RFP enumerates resource needs identified by its planners in qualitative terms, but without very much numerical specificity with respect to costs. Estimated need for baseload and peaking resources are indicated to be about 400-500 MW and 200 MW respectively between 1996 and 1999. During this period SMUD will be seeking to replace contracts with Southern California Edison (SCE) and PG&E

that will cost $90/kW-yr, escalating at $5/kW- yr, for generation capacity, and approximately 11,500 Btu/kWh times the average cost of utility purchased gas for energy. In addition, SMUD pays PG&E $12/kW-yr for transmission service on the SCE purchase. These costs, which are publicly known, but not included in the RFP represent the costs against which bidders are competing.

The RFP goes into considerable detail on two issues, transmission and dispatchability. Both of these are concerns that arise out of the geographically limited territory served by the utility. SMUD's resource base is small and its generation does not exhibit substantial operational flexibility to meet load fluctuations. Therefore, resources acquired through bidding will have to meet the need for dispatchability, and may well require transmission service to reach the demand. In both cases, the attributes are difficult to analyze.

With regard to transmission, SMUD makes the unusual offer of providing individual bidders up to two hours of no-cost consultation on the general feasibility and cost of specific transmission alternatives. This service will be provided during the bid preparation period so that proposals will not face major stumbling blocks or large unanticipated costs. There will be a second stage of more thorough evaluation for those bids which are chosen for the "short list" group with whom SMUD will negotiate in detail. At this second stage detailed studies will be conducted for which the bidder will be charged by the relevant party which in addition to SMUD may include PG&E or the Western Area Power Administration (WAPA).

The dispatchability attribute includes all of these aspects of power generation required to meet load. These have been defined below to include curtailment, commitment and chronological constraints (Section 4.1.1). The RFP refers generally to evaluating operational characteristics using "a long range planning model to simulate the costs of operating the system with the proposed resource." As the discussion below indicates, however, it is impossible in the current state of the art to evaluate all dispatchability components in a single modelling framework. Given the severity of the operational constraints facing SMUD, this part of the evaluation process will present major challenges.

There are several other unique features to the SMUD RFP. One of the more unusual is the discussion of the Rancho Seco power plant. Although this facility has been shut down as a result of voter dissatisfaction, Rancho Seco remains a prominent feature of the SMUD system. It represents both an asset and a liability. The asset value lies primarily in the site and related power generation equipment which might be used by an outside developer either for fossil fuel generation, or even as a nuclear facility. SMUD has previously reviewed and rejected several proposals to operate Rancho Seco as a nuclear facility. Presumably there would be more interest in re-powering the plant using fossil fuels. The Midland Cogeneration Venture of CMS Energy in Michigan represents a somewhat similar case. On the negative side, in any event Rancho Seco will eventually have to be decommissioned. Any re-powering option would probably involve bearing some of those costs.

Reserve requirements also play a unique role in the bid evaluation system. Because SMUD is beginning operation as its own control area, it becomes responsible for meeting its own reserve requirements. In a section of the RFP titled "Resource Diversity," this constraint is translated into a maximum project size of 135 MW. This limit arises from SMUD's interpretation of its planning reserve obligation under Western States Coordinating Council (WSCC) guidelines. It is not an absolute constraint in the sense that no bid will be accepted if it has larger capacity. What it does mean is that such bids will be assessed some penalty reflecting the incremental reserve requirement above 135 MW that they impose.

An issue which is not addressed explicitly involves the scale economy of multiple large bids. Suppose two bidders each offered attractively priced 200 MW bids. Instead of imposing reserve penalties of 65 MW (i.e. 200-135=65) on each bidder, the acceptance of both bids in the resource plan would mean that each bid should only be penalized for the reserve cost of 32.5 MW. While SMUD has given no indication of how it would handle such an eventuality, it cannot be ruled out. The attempt made by JCPL to limit bids to 100 MW maximum size was effectively and efficiently circumvented by a development team that bid twin 100 MW projects on a cost competitive basis.

Finally, SMUD has chosen not to offer a standard contract to bidders. This is unusual in recent RFPs. The argument in favor of standard contracts is that the utility can define its requirements precisely in advance, and limit the scope of negotiations. Private producers also have an interest in limiting the scope of negotiations. SMUD has said that it feels there will be sufficient variation among proposals that they do not feel a standard contract would have any value.

1.1.7 Los Angeles Department of Water and Power

The Los Angeles Department of Water and Power (LADWP) is the largest municipally owned electric utility in the United States. It currently has generating resources of 7420 MW of which 45% (or 3113 MW) are oil- and gas-fired resources located in the environmentally sensitive South Coast Air Basin. LADWP owns 1797 MW of coal-fired capacity located in Utah and Arizona. Other unique resources are the Castaic pumped storage facility (1247 MW) and an extensive interstate network of high voltage transmission facilities. To meet anticipated service area peak demand growth of about 1300 MW over the next ten years, LADWP will re-power some old facilities, develop California geothermal resources and expand its transmission network. In addition to this it is seeking 600 MW of capacity through competitive bidding, to be delivered during the 1996-2000 period.

The RFP specifying this resource need was issued in June, 1990 (LADWP, 1990). While the document gives substantial detail about preferences and evaluation procedures, it is essentially still a closed system without precise self-scoring procedures. LADWP will select a small group of respondents for subsequent negotiations, but will not allow price changes to be negotiated. The RFP distinguishes respondents in three categories: system sales, existing facilities, and new facilities. Minimum threshold requirements are slightly more severe for the new facilities category than the others. The principal difference is that project financed respondents offering new facilities must hold at least 10% equity in the resource and agree to financial audits by LADWP. Project security of $25/kW is not required for a system sale, but is required of other respondents. Minimum criteria for all respondents include contract offers of at least 10 years, and transmission impact studies. Maximum project size is 250 MW.

The RFP is very explicit on the subject of transmission studies that will be required of all respondents. For projects of less than 200 MW, LADWP will perform the required transmission studies at a cost that will be billed to respondents. Minimum costs are $500 for projects in the 10 to 75 MW range and $1500 for projects larger than 75 MW. For projects that are greater than 200 MW and located outside the South Coast Air Basin, the respondents will have to conduct the required studies themselves. The requirements are specified in detail, and include power flow studies, stability studies, and short circuit studies. LADWP may require additional studies in these cases, and will verify results. For this category of respondent, the RFP indicates that preliminary results will be acceptable at the proposal due date, but that final results will be involved at the negotiation stage.

Table 1-1: RFP Summary

	Need	Period	Type of Capacity	Transmission	Planning/ Evaluation
VP	1100 MW	1995-97	Base-Intermediate	Bidder Must get Wheeling	Capacity Expansion study
JCPL	270 MW	by 1994		Bidder must get Wheeling	Self-scoring system
FPL	800 MW	1994-97	Base-Intermediate Non Oil/Gas	Bidder must get Wheeling	Alternative Resource Costs
PSI	1300 MW	1993-2000	Peaking	Assist Out of Area Wheeling	Capacity Expansion Study (limited)
SMUD	600-700 MW	1996-99	4-500 MW Baseload 200 MW Peaking	Assist Out of Area Wheeling	Capacity Expansion Study (limited)
LADWP	600 MW	1996-2000		Extensive Impact Studies	

The RFP contains a section called "Preferred Project Attributes." Various dispatchability attributes are listed here. "Must run" conditions, especially during off-peak periods have negative value. Pre-scheduling is desirable. For system sales, the ability to dispatch between 0 and 100 percent of capacity is preferred. For individual facilities, minimum loading of no more than one-third of capacity for baseload and intermediate facilities, and one-half capacity for peaking facilities is preferred. Contracts of 25 years or longer are desirable. No front-loading of capacity payments is also listed here as a preferred attribute.

1.2 Contract Analysis

1.2.1 Introduction

RFPs tell what power purchasers would like to buy in general terms. Power contracts tell what they, in fact, buy in very specific terms. Therefore a review of recent contracts is a useful way of summarizing market behavior. In this section we survey the principal features of a number of power purchase contracts affecting projects that are expected to be operational in the next several years.

Power purchase contracts are typically long complex documents. We concentrate attention in this discussion on pricing terms and operational aspects. Subjects such as testing procedures, liens and assignments, liability, and interconnection are neglected, even though they comprise the largest portion of the actual contract text.

The principal purpose of this discussion is to define more precisely the dispatchability conditions which are coming into increasing importance in the private power market. All the RFPs surveyed in Section 1.1 placed emphasis on dispatchability. The tendency toward "closed" bid evaluation systems, however, makes it difficult to know precisely what is meant by this term and how it is valued. Reviewing power purchase contracts can help to specify market requirements and set the stage for systematic analysis.

Many of the contracts discussed below are filed with the Federal Energy Regulatory Commission (FERC) because the projects are Independent Power Producers (IPPs) rather than Qualifying Facilities (QFs) under PURPA. Therefore the rates charged by the seller must be deemed just and reasonable. We do not address FERC's review process here, but simply assume that where these contracts arose out of competitive bidding procedures, they will meet the just and reasonable standard.

Our survey will characterize each project briefly, describe the structure and level of prices and link these with the operational, i.e. dispatchability requirements of the contract. Where appropriate, we will make comparisons with other facilities or proposed projects.

1.2.2 Dartmouth Power Associates

This contract (FERC Docket No. ER-90-278) between Dartmouth Power Associates and Commonwealth Electric of Massachusetts is for 50 MW out of 67.3 MW of project capacity. This contract emerged from negotiation rather than competitive bidding. The proposed in-service date is July 1, 1992. It is a gas-fired project using natural gas that will be delivered from Alberta, Canada. The structure of costs for the fuel supply are heavily weighted toward pipeline charges for gas transportation. According to cost estimates in Appendix B of the contract, the fixed demand costs for pipeline capacity will represent about 80% of the total transportation charges. The total cost of power estimated for the initial year of operation is 5.645 cents/kWh.

Fuel transport represents 1.54 cents or 27% of the total. These estimate assume a 91% capacity factor for the plant. Table 1-2 gives details of the pricing structure.

Table 1-2
Dartmouth Power Associates: Pricing Terms

Fixed Charges ($/kW-yr)		Escalation
Capacity Cost	46.25	GNP Index
Investment Cost	167.32	Levelized
Pipeline Demand	94.43	Tariff
Sum	$308.00	
Energy Charge		
Fuel (1992 estimate)	$1.655/MMBtu	Gas Index
Pipeline Variable	.42/MMBtu	Tariff
Sum (1992 estimate)	$2.075/MMBtu	
Contract Heat Rate	8583 Btu/kWh	
Total Cost of Power (cents/kWh)		
Fixed Cost	3.864	(=308/(8760*.91)
Variable	1.781	(=2.075/.008583)
Sum	5.645	

Table 1-2 illustrates that this project may operate with natural gas, but that it is priced much like a baseload coal plant. Fixed charges of $308/kW-yr, of which nearly half will escalate at GNP or tariff rates, exceed estimates of the levelized fixed charges of the Clover facility sponsored by Virginia Power and Old Dominion Electric Co-operative due in operation in 1994. The Clover project is an 800 MW pulverized coal generating station being built in Virginia. In testimony before the State Corporation Commission, Virginia Power made estimates of the levelized fixed costs of this project which were approximately $310/kW-yr (Ellis, 1989).

Given the cost structure shown in Table 1-2, it is unlikely that the Dartmouth project will be operated in anything other than baseload service. The variable costs of power are likely to remain very competitive with other resources in the New England region. The gas index used to escalate fuel costs is weighted 50% to the market price of Alberta gas and 50% to U.S. gas prices. Using the Canadian prices should keep the escalation rate below that which might be expected in the U.S. alone. The contract heat rate reflects the combined cycle technology being used in this project. The value of 8583 Btu/kWh is close to recent estimates made by EPRI of combined cycle efficiency for projects in this size range (JCPL, 1989).

The Dartmouth project is nonetheless front-loaded in its costs compared to the avoided cost estimate made by Commonwealth Electric to evaluate the project. To secure the ratepayers' exposure, Dartmouth must post irrevocable letters of credit in the amounts of the estimated excess of price over avoided cost (plus interest at 7.5%). These specific dollar estimates are incorporated as contract terms (Article 15.4) without any provision to correct these amounts as conditions may change.

Many of the features of the Dartmouth contract re-appear in other settings. It is convenient to begin this review with their project because the pricing terms are so explicit and transparent.

1.2.3 Enron Power Enterprise

This contract (FERC Docket No. ER-90-290) between Enron Power Enterprise and New England Power Company is for a 58% entitlement to a 140 MW gas-fired project. Commercial operation is expected to begin in July, 1992. Like Dartmouth Power, Enron is also priced on a basis assuming Alberta gas. In fact, the fuel will be liquified natural gas (LNG), but the pricing will reflect opportunity costs. The pricing terms, therefore, have the same general structure; namely heavily weighted toward fixed costs with low variable energy costs.

Enron is nominally described as a dispatchable project, just like Dartmouth Power, but the contract makes explicit that it is really meant to be a baseload facility. This intention is incorporated into price renegotiation provisions contained in "Schedule D Determination of the Contract Payment." We can see how this emerges from a brief summary of the contract pricing terms. The basic pricing structure of the contract is given by the two equations below.

Monthly Capability Charge (\$/kW) = [(16.00*F) +(9.66*(A)*(TC)) + (1.95*(TL)],

where:

F is a fixed escalation factor of 1.05/yr starting in year 2 of operation, A is an availability index, TC is an index based on the Alberta to Boston pipeline demand tariff charge, TL is an index based on local gas pipeline tariff demand charges.

Kilowatthour Charge (\$/kWh) = \$0.0119 *R,

where:

R is an index based on the Weighted New England Power Pool Fossil Energy Cost.

The petition for FERC approval of rates based on this pricing formula asserts that all numerical values are at their 1988 base levels, except the \$16/kW-month charge which is set at the 1992 level (Hollis, et al., 1990). If we assume 5%/year escalation in the indices TC and TL, then the 1992 monthly capability charge would be \$30.11. On an annual basis this is \$361.34/kW-year. The kilowatthour charge, if also escalated at 5%/year would be 14.46 mills/kWh. Thus the fixed charges of the Enron project exceed those of Dartmouth, but the variable costs are lower. At the 91% capacity factor assumed by Dartmouth, the cost of power in 1992 for Enron is 5.986 cents per kWh, which is about 6% more than Dartmouth. If the total variable cost escalation over the 1988-1992 period were only 10%, then the Enron project would be only about 3.5% higher in cost than the Dartmouth project.

The variable costs of Enron are indexed to New England Power Pool fossil fuel costs. Since there is significant coal combustion in New England, this is equivalent to partial indexation to U.S. oil and gas costs. The base price of 1.19 cents per kilowatt hour, which reflects combined cycle conversion efficiency and LNG variable costs, is subject to renegotiation by either party in years five or ten of the contract. The principal constraint on any renegotiated price is that it must be sufficient to have achieved an "output factor" of at least 80% in the previous year had the renegotiated price been the dispatch price ("output factor" is defined as actual output divided by the product of available hours times project capacity).

The price renegotiation provision makes it very clear that this project is only dispatchable in form, but is fundamentally a baseload facility. The economic structure requires that it be operated in this fashion, otherwise the fixed LNG costs would weigh too heavily in total cost.

As a check on the overall costs of power from this project, the contract contains a monthly capability price reduction provision. After the ninth year of operation, the buyer has the right to reduce the fixed payments if the total cost of power from the project exceeds New England Power's average cost of generation. Schedule G lists annual maximum percentage reductions in the capacity price that can be triggered under the cost comparison test. These percentages start at 10% and reach a maximum of 25%. If this clause is invoked, the seller has the right to terminate the contract.

1.2.4 Doswell Limited Partnership

This contract between Doswell Limited Partnership and Virginia Power is for 300 MW of gas-fired dispatchable power. The anticipated date of commercial operation is December 1, 1991. There are, in fact, two identical contracts for two projects of 300 MW each, making this facility one of the largest Independent Power Producers yet to emerge. Doswell is a successor to Intercontinental Energy Corporation, which had originally contracted with Virginia Power for two Qualifying Facility projects of this size. The original Intercontinental contracts resulted from a 1986 Virginia Power solicitation. Doswell is owned by Diamond Energy Incorporated, a subsidiary of Mitsubishi Corporation.

Unlike Dartmouth and Enron, Doswell is genuinely intended to be a dispatchable project. Unlike the New England region, Virginia has an abundant coal resource base with which gas-fired resources must compete. Furthermore, the Doswell project will rely on the same pipeline supply infrastructure as Virginia Power's own gas-fired generators. Therefore, the fuel cost of the project cannot be expected to be substantially below that of competing resources.

Capacity payments for Doswell are substantially below the level in the Dartmouth and Enron contracts. The basic monthly capacity payment is $10.2567 per kW for the first 15 years, and $5.8933 per kW for the following ten years. On an annual basis this is $123/kW and $70.72/kW respectively (Article 10.9(a)). These payments do not include the fixed cost of gas transportation, storage and fuel inventory carrying charges. It is highly unlikely that the sum of these costs would come anywhere near the fixed costs of pipeline capacity in the Dartmouth and Enron contracts.

The Doswell contract takes a proxy plant approach to pricing and operation. Virginia Power's Chesterfield 7 combined cycle plant represents the most directly comparable facility. It uses the same fuel supply and similar combined cycle technology. The contract establishes variable cost parameters for Doswell that are designed explicitly to parallel Chesterfield 7. The variable price formula is critical for economic dispatch, because it will be the basis for operating decisions. The formula (from Article 10.2 of the contract) is

Energy Purchase Price = Chesterfield 7 Delivered Fuel Price ($/MMBtu) * 0.007700 (MMBtu/kWh) *1.1 .

The contract devotes considerable attention to contingencies that might interfere with the intended parallelism between Doswell's fuel costs and those facing Chesterfield 7. The heat rate term in the formula (0.007700 MMBtu/kWh) is approximately the expected full-load heat rate of the Chesterfield unit. The 1.1 adjustment factor, which is the most interesting aspect of the formula, is not discussed at all. Conversations with attorneys representing Doswell characterize the adjustment factor as a means of accounting for the production inefficiencies of the project operating at less than its maximum capacity. This is a very important issue which requires further exposition.

Combined cycle generation is becoming a major technology for new power projects. The basic configuration involves the coupling of a steam generator to a combustion turbine. The hot turbine exhaust gases are used to drive the steam generator. The combination increases overall fuel efficiency. There is, however, no single generic combined cycle configuration. Not only can the size and efficiency of the combustion turbines and steam generators vary, but the combinations can as well. Chesterfield 7 uses two combustion turbines and one steam turbine for a total capacity of about 210 MW. This configuration is represented in the 1989 EPRI Technical Assessment Guide as Technology Number 46.2, where heat rate variations for different load levels are given. These are reproduced as Table 1-3 below.

Table 1-3
Advanced Combined Cycle Net Heat Rate (Btu/kWh)

Full Load	7514
75% Load	7885
50% Load	8860
25% Load	11860
Average Annual	7740

The heat rate variations shown in Table 1-3 represent the costs facing the Virginia Power dispatcher when deciding whether, and how much, to load Chesterfield 7. We will see below that the situation is actually more complex. Forgetting that possibility for the moment, however, it is clear that Doswell will appear to the dispatcher only as an 8470 (=7700*1.1) Btu/kWh gas-fired resource. There is no guarantee that the project will be operated in a fashion that results in its actually achieving the contract heat rate. All we can say with any probability is that the pricing formula should result in Doswell operating less than Chesterfield 7.

Because the operator cannot "see" the higher efficiency performance of the project at higher output levels, there will be an incentive to dispatch the unit after Chesterfield 7. This means that the average heat rate of Doswell could be higher than that of Chesterfield 7, because it will run less and potentially at lower average power levels. Recent Virginia Power forecasts of the average Chesterfield 7 heat rate are in the range of 7700-7900 Btu/kWh (Virginia Power, 1989). If the results of the dispatch priority effect due to the contract heat rate representation are mild, then Doswell will not suffer financially. If costs systematically exceed the contract heat rate, then the financial consequences will be negative. Opportunities for redetermination of the energy purchase price, as listed in Article 10.7 of the contract, do not include the type of dispatch effect outlined here.

The contractual solution to this potential difficulty is a constraint defined in Article 1.24 "Design Limits." This specifies that the dispatch "require operation of the Facility at levels *no less than eighty (80) percent of peak load capacity* (emphasis added), except during start-ups, shutdowns or Emergencies." Table 1-3 shows that this operating constraint will virtually guarantee average heat rates below the contract level.

The effect of the Design Limit operating constraint is to limit substantially the ability of the project to follow load fluctuations. It is either operating at 80-100%, or it is off. This inflexibility is in sharp contrast to the preference expressed in the Virginia Power 1989 RFP discussed above that baseload and intermediate capacity be capable of operating down to minimum levels of 25% of capacity.

Other operating issues are not clearly specified by the contract. Most of Article 7, "Control and Operation of the Facility: Dispatching," is concerned with exchanges of information involving availability, maintenance plans, emergencies and projected operating schedules. There are penalties associated with failure to follow the instructions of the Virginia Power dispatcher (Article 10.9 (d)), and for low availability (Article 10.9(c)).

1.2.5 TECO Power Services

FERC Docket No. ER-90-164 is a set of three contracts between TECO Power Services (a subsidiary of TECO Energy which also owns Tampa Electric), Seminole Electric Co-operative, and Tampa Electric itself. This is an extremely complicated and unique arrangement, only certain aspects of which we will describe. The basic situation involves the need of Seminole for back-up power to support its native load requirements that are currently served by two 600 MW coal plants. Seminole contracts for 440 MW of back-up service expire in 1992. As the result of an RFP, TECO Power Services was chosen to meet these needs by building a 220 MW combined cycle (CC) plant, a 75 MW combustion turbine (CT), both fired by natural gas, and to deliver 145 MW of coal power to be purchased from Tampa Electric (Woodbury, 1989). FERC rejected the TECO rate filing, raising issues involving TECO's affiliate relations with Tampa (FERC, 1990). We ignore these questions, which may be relitigated, and concentrate on the dispatch issues associated with the CC/CT facilities.

The CC/CT facilities, to be constructed by 1993, would be operated through a complex system of priority rights. Seminole would have first call on the CC/CT facilities to meet its back-up needs; Tampa would have second call for native load requirements. There is an active economy energy market in Florida, so part of the value of the CC/CT facilities would lie in sales there. Seminole would have third call on the CC/CT to serve this market, and Tampa would have fourth call for that purpose. The FERC filing specifies all obligations in three contracts. One between TECO and Seminole (T-S), and two between TECO and Tampa. We will neglect the TECO-Tampa (T-T) contract involving the coal facility, and only consider the contract involving the CC/CT facilities.

Allocation of the fixed costs for the CC/CT facilities is on a 60% Seminole, 40% Tampa basis. Monthly capacity charges for the first ten years of the project are $1,691,083 for Seminole (T-S, Article 6.4) and $1,137,250 for Tampa (T-T, Article 6.4). On an annual basis this is $115/kW. For the next ten years these costs increase about 4%. All other fixed costs are allocated on a 60/40 basis.

Energy costs will be allocated to the two parties in proportion to the amount of the facility's output that each uses (for either native load or economy sales). The contract includes in Appendix J (both T-S and T-T) an explicit formula for treating CC fuel costs; CT fuel costs are treated in Appendix F. The illustrative example in the combined cycle case is sufficiently detailed and interesting that it is reproduced here as Table 1-4.

Table 1-4 represents a particular pattern of combined cycle operation over a twenty four hour period. The columns show output and efficiency variations for the two combustion turbines CT 1A and CT 1B, steam turbine (ST 1) output, on-site station service (AUX MWh), fuel use per hour for each CT, and hourly average fuel cc per MWh for total output. In the last two columns a hypothetical allocation of output and cost is shown for one of the parties (in this case Seminole).

The pattern of total CC output is at first glance unusual. Production peaks at 9 AM and again at 6 and 7 PM. During the hours from noon to 3 PM output falls to about one-third the maximum. This pattern is nearly inverse to the typical daily load curve. There is, however, a very good reason for this pattern. The CC unit is providing a function known as "ramping." The mid- morning and early evening hours often experience the most rapid load changes on the power system. Not all generators can respond quickly to changes in power demand. In this situation there is a premium on resources that can change output levels rapidly and over a large range. Further discussion of such issues is taken up in Chapter 4 below.

Given that Table 1-4 represents a "ramping" service demand, there is still an unusual phenomenon during the Noon to 3PM interval. During this period, both CT 1A and CT 1B are operating at 25MW, or one-third capacity. Their heat rates at this level are quite poor, 15,700 Btu/kWh compared to 10,200 Btu/kWh at full capacity. A lower operating cost during this period could be achieved if one of the combustion turbines were just shut down. Then the operating efficiency would resemble hour 11; one CT producing 50 MW at 11,100 Btu/kWh, the ST producing 20 MW, and total average fuel cost of $16.23 instead of $23.43. Figure 1 shows the hourly variations in output and heat rate.

This issue is addressed qualitatively in Article 5.4.2.1, "Rapid Starts; Short Cycling." Here the contract invokes the general principle that minimizing rapid starts and short cycling, "pursuant to manufacturer's recommendations," will in the long run maximize the availability and reliability of the facility. The Table 1-4 example, therefore, represents the short term cost associated with this long term economy. Because the operator of the facility knows that full power will be needed later, he does not shut down both turbines during a period of low demand in order to minimize start-ups.

The contract prescribes that detailed recommendations on this subject and similar operational issues be determined by an Operating Committee representing Seminole, Tampa and TECO. Day ahead schedules will be required and procedures are defined for accommodating the system of priority rights to scheduling the facility for both native loads and off-system sales. A mechanism for dispute resolution is included in the contract. Such mechanisms are common in other, less complex arrangements as well.

There are numerous other features of the TECO arrangement with Seminole and Tampa. These include performance guarantees, purchase options, and provisions for replacing the coal-fired portion of the back-up service. We have focused attention on the CC/CT aspect because it illustrates features of dispatchability in more detail than other contracts. The unusually complex nature of this agreement makes great clarity important.

1.2.6 Commonwealth Atlantic

This contract between Commonwealth Atlantic Limited Partnership and Virginia Power is for 240 MW of peaking capacity, due in service on March 1, 1992. The project consists of three

Table 1-4
TECO Power Services/Seminole Electric Cooperative
FERC Docket No. ER-90-164

Combined Cycle Fuel Cost

EXAMPLE CALCULATION OF THEORETICAL TOTAL FUEL CONSUMPTION FOR CC 1

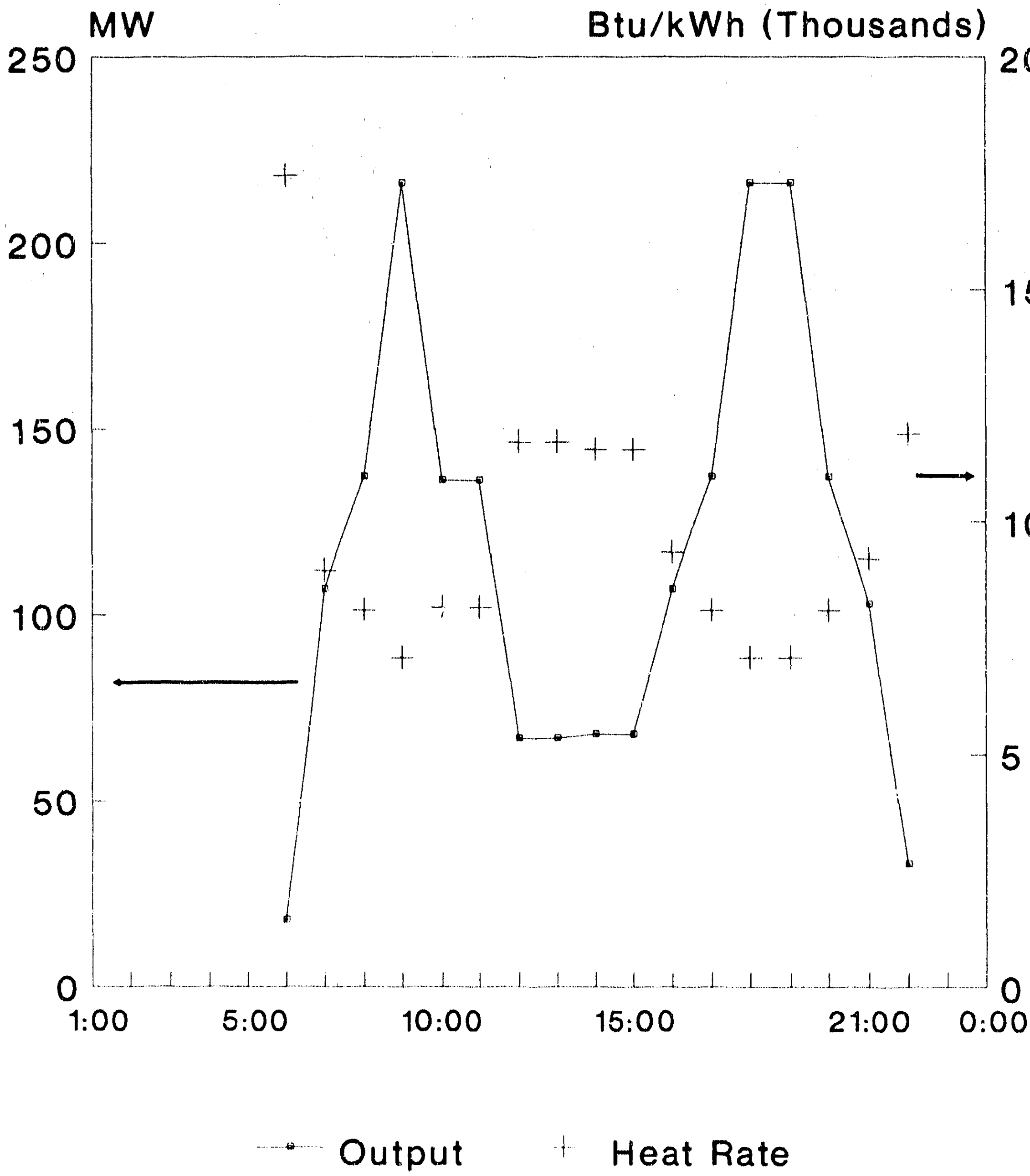
	CTA			CTB								
Hour	MWh	HR	MMBTU	MWh	HR	MWBTU	ST 1 MWh	AUX MWh	MWh_{cc}	$/MWh	MWh_s	TFC_3
1	0		0	0		0	0	1	0	$0	0	$0.00
2	0		0	0		0	0	1	0	$0	0	$0.00
3	0		0	0		0	0	1	0	$0	0	$0.00
4	0		0	0		0	0	1	0	$0	0	$0.00
5	0		0	0		0	0	1	0	$0	0	$0.00
6	20	15,700	314.0	0		0	0	2	18	$34.89	18	$678.02
7	50	11,100	555.0	30	13,400	402.0	30	3	107	$17.89	100	$1,789.00
8	50	11,100	555.0	50	11,100	555.0	40	3	137	$16.20	100	$1,620.00
9	75	10,200	765.0	75	10,200	765.0	70	4	216	$14.17	100	$1,417.00
0	50	11,100	555.0	50	11,100	555.0	40	4	136	$16.32	100	$1,632.00
1	50	11,100	555.0	50	11,100	555.5	40	4	136	$16.32	100	$1,632.00
2	25	15,700	392.5	25	15,700	392.5	20	3	67	$23.43	50	$1,171.50
3	25	15,700	392.5	25	15,700	392.5	20	3	67	$23.43	50	$1,171.50
4	25	15,700	392.5	25	15,700	392.5	20	2	68	$23.09	50	$1,154.5
5	25	15,700	392.5	25	15,700	392.5	20	2	68	$23.09	50	$1,154.50
6	40	12,500	500.0	40	12,500	500.0	30	3	107	$18.69	100	$1,869.00
7	50	11,100	555.0	50	11,100	555.0	40	3	137	$16.20	100	$1,620.00
8	75	10,200	765.0	75	10,200	765.0	70	4	216	$14.17	100	$1,417.00
9	75	10,200	765.0	75	10,200	765.0	70	4	216	$14.17	100	$1,417.00
10	50	11,100	555.0	50	11,100	555.0	40	3	137	$16.20	100	$1,620.00
11	25	15,700	392.5	50	11,100	555.0	30	2	103	$18.40	50	$920.00
12	0		0	25	15,700	392.5	10	2	33	$23.79	33	$785.07
13	0		0	0		0	0	1	0	$0	0	$0.00
14	0		0	0		0	0	1	0	$0	0	$0.00
TOTAL	710		8401.5	720		8489.5	590	58	1969		1320	$23,492.30

Notes:

MWh_{CT}	= Gross Generation from Each CT Unit
HR_{CT}	= Gross Heat Rate Corresponding to Hourly Load According to Heat Rate Curve for each CT Unit
O/G	= Fuel Used Predominately in each CT Unit During the Hour
$MMBTU_{CT}$	= (MWh_{CT} X HR_{CT})/1000 for each CT Unit
$/MWh	= Fuel Cost (PFC) x $MMBTU_{CT}$ for both CTs Divided by CC Net Generation (MWh_{cc} (Example Assumes Natural Gas Price (PFC) of $2.00/MMBTU)
ST 1 MWh	= MWh Generation from the Steam Turbine Generator
AUX MWh	= Station Service for CC 1
(MWh_{cc})	= MWh_{CTA} + MWh_{CTB} + ST 1 MWh - AUX MWh
MWh_s	= Net Energy Generated for Seminole including Seminole's Sales of Schedule A & B
TFC_s	= Theoretical Total Fuel Consumption Costs for Seminole

Figure 1-1

Output and Heat Rate



80 MW combustion turbines that will operate on natural gas (if available) during the summer and distillate oil during the winter season.

The capacity price will be set under a formula that is linked to U.S.Treasury bond yields. The purpose of this linkage is to support leveraged lease payments (Article 10C.15 (a)). If the appropriate bond yield were calculated, for example, to be 9%, then the capacity payments (as specified in Table 10.1) would be $5.377/kW-month for the six summer period months and $4.151/kW-month for the six winter period months. In this example, the annual payment would be $57.17/kW. The table specifies $51.23/kW-year if the bond yield were 7%, and $64.30/kW-year if the bond yield were 11%. In addition there will be fixed O & M payments of $0.686/kW-month for the summer period and $0.5295/kW-month for the winter period. These prices are expressed in 1988 dollars and will be indexed to the GNP deflator.

The variable price is set using a contract heat rate, a base year fuel price and a monthly fuel cost indexation procedure. The contract heat rate is 12,349 Btu/kWh for the winter period, and 12,540 Btu/kWh for the summer period. The summer base fuel price is $1.75/MMBtu effective January 1, 1988, and the winter base fuel price is $4.00/MMBtu. In the event that gas pipeline facilities have not been constructed by the date of operation, the winter price will be used for the summer period.

This project was selected as a result of the 1988 Virginia Power solicitation, which emphasized dispatchability. The "Design Limits" section of the contract, Article 1.10, specifies the operational parameters for the project in great detail. Each combustion turbine will operate only over the range from 75% to 100% of maximum electrical output. These output levels vary with ambient temperature and fuel as specified in Article 1.10(a). The total facility output can vary over the range from 25% to 100%, except for the range between 33% and 50% and 67% through 75%. The combination of three units operating between 75% and 100% provides this total facility flexibility and the attendant limitations.

Start-up time is 45 minutes for each turbine. The utility may operate the turbines individually, sequentially or simultaneously. There are two constraints on start-ups. Each turbine is limited to two (2) starts per day, and one hundred fifty (150) per year. These constraints will be discussed below in Section 4.

Minimum operating time for each turbine is one hour. The minimum interval between shutdown and the next start-up, i.e., minimum down-time, is one hour. Maximum operating duration, i.e., up-time, is ten (10) hours per day. The contract also specifies a maximum "ramp rate," i.e. rate at which output may be increased or decreased. This is 5 MW per minute, for the facility as a whole. Finally, there are limits on the maximum number of total hours that the facility may operate in a year. For the first two years of operation, the maximum is 500 hours. Thereafter, the facility may be operated for a maximum of 1000 hours per year.

This level of operational detail exceeds anything given in the other contracts we have reviewed. The TECO contract will presumably result in specifications at this level of detail through the facility's Operating Committee. The Doswell contract also envisions a further specification of operating limits to be defined several months before operation commences. Although there is language relating to operating constraints in both Dartmouth and Enron, it is vague.

1.2.7 Cogen Technologies

This twenty-five year contract between Cogen Technologies of Linden, New Jersey, and Consolidated Edison Company of New York (Con Ed) involves a large-scale dispatchable gas-fired cogeneration project. The project did not emerge from competitive bidding, but because of its size and features it is useful to include in this review. The contract was approved by the New York Public Service Commission Case 28689; Contract 344, on September 7, 1989.

There are a number of uncertainties surrounding this project which include its exact capacity, its date of operation and the steam hosts who will purchase thermal energy from the project. The project will have a minimum of 440 MW to sell, but may be upgraded to a capacity of 539 MW, or even 594 MW. This latter size depends upon the developer abandoning another project. The contract does not specify an expected date of commercial operation. However, termination clauses specify that construction must have begun by September, 1991 and commercial operation should commence by March, 1994. Some slippage in these dates is allowed subject to penalty clauses. Finally, the project will be sited at the Exxon Bayway refinery, but the exact nature of the steam demand is uncertain.

Pricing and dispatch conditions for the project make it an interesting comparison with other projects. The pricing terms (Article 4) are expressed entirely on a per kWh basis. This form is unusual for dispatchable projects which typically separate fixed from variable payments; only the latter are expressed on a per unit basis. The price terms are expressed as follows:

		@85% Capacity Factor
Fixed Component	$0.018553/kWh	$138.14/kW-yr
O & M Component	0.009/kWh	67.01/kW-yr
Fuel Component	0.02634/kWh	

The Fixed Component is unchanged over the life of the contract. The O&M Component is indexed to the Consumer's Price Index with December, 1988 as the base year. The Fuel Component is indexed to Con Ed's cost of gas. We express the Fixed and O&M Components on an annual basis at 85% capacity factor, because these costs will be incurred by Con Ed even when curtailment rights are exercised (Article 4.5). This means that the unit cost price quotation is not really meaningful; these are basically fixed costs.

The prices paid to the project exceed Con Ed's estimated avoided cost in the first few years of operation. The contract requires security for this difference (Article 5). The amount of security depends on two factors, the start date of the facility, and its ultimate capacity. The contract includes a table which calculates annual security requirements, including 11% interest, as a function of start date. If the capacity is increased from 440 MW, these requirements would scale up in proportion. The contract allows for a variety of forms of security including letters of credit, insurance, and/or corporate guarantees. Con Ed retains exclusive right to determine the form of security it will accept.

The dispatch conditions amount to curtailment rights (Article 11.2). There is no provision for start-ups and shutdowns, nor is there any discussion of ramping restrictions. The curtailment provisions over the first 15 years of the contract are separated into weekday and weekend rules. During the weekdays, with four hours notice, Con Ed may restrict output to 82% of contract capacity (whatever that may turn out to be). On the weekend, with 24 hours notice, curtailment can be down to 47% of capacity. For this purpose, the weekend is defined to begin at 10 PM on Friday and end at 8AM on Monday, or 58 hours of the week. These restrictions amount to a minimum capacity factor of project of just under 70% (((.82*110)+(.47*58))/168) = .6992). In the last 10 years of the contract curtailment to 47% of capacity is possible at any time, subject to a limitation on the total number of curtailment requests (one request per 50 hours of operation not subject to this request).

Finally, this project is located outside of the Con Ed service territory. The problem of delivery to Con Ed is assumed by the developer. It is not clear whether the project will construct its own direct transmission linkage with Con Ed, or whether it will negotiate a wheeling contract with Public Service Electric and Gas, the New Jersey utility in whose service territory the project is located.

1.2.8 Multitrade Limited Partnership

All of the contracts discussed so far involve gas-fired projects. This reflects the dominant position of gas fuel in the private power market. The Multitrade Limited Partnership contract with Virginia Power represents the first of a series of coal-fired projects that we review in this section. Multitrade is a 76 MW project expected in commercial operation on or about November 30, 1992. This project was selected as one of the winning bids in the 1988 Virginia Power RFP (along with Commonwealth Atlantic).

The pricing features of the project make a remarkable contrast with Dartmouth, Enron and Cogen. The first two are gas projects whose split between fixed and variable cost resembles coal. Multitrade, based on coal, is priced initially in a fashion that resembles Cogen, a traditionally structured gas project. The pricing formula for Multitrade involves a schedule of fixed costs that begins at $228/kW-yr in the first year of operation, escalates at an average annual rate of 0.7%/yr to $253/kw-yr in the fifteenth year of operation, and then declines in the last ten years to a level that fluctuates around $208/kW-yr. On the energy side the price in 1988 dollars is $0.0265/kWh. These costs resemble the structure of the Cogen contract. The principal difference involves the cost escalation indices.

The Multitrade fixed cost starts out about 11% higher than Cogen ((228/205) = 1.112). The escalation of the O&M component at the CPI would probably bring the total Cogen fixed cost in year 15 to a level about 10% greater than the maximum yearly fixed cost of Multitrade. Suppose the CPI averaged 5% over a 15 year period. This would more than double the Cogen annual O&M component to about $139/kW-yr. Total fixed cost at that time would be $277/kW-yr, compared to $253 for Multitrade.

The Multitrade variable costs consist of two components. The fuel component is $0.0225/kWh in 1988 dollars. There is an O&M component of $0.004/kWh. The fuel component is indexed to the Virginia Power cost of coal. The O&M component is indexed to the GNP Implicit Price Deflator. These two indices are both expected to grow much more slowly than the gas cost index which will be used for Cogen.

The dispatch conditions for Multitrade involve very few constraints. The Design Limits section of the contract specify very low minimum capacity. Apparently the project involves two generators. The minimum capacity for each is 15 MW. For a cold start, i.e. when the unit has been off for more than 16 hours, it takes 13.5 hours to reach maximum capacity. The ramp rate, after startup, is specified to be 2.5% of capacity per minute. Given the relatively high variable cost of the project, it will probably operate at annual capacity factors of 50-60% in its early years of operation. This range is bounded by the costs of Chesterfield 7, an efficient gas combined cycle plant with running costs slightly higher than Multitrade and by Bremo 3, Virginia Power's least efficient coal plant. Bremo 3 has a heat rate of approximately 11,400 Btu/kWh, which is better than Multitrade. The capacity factor estimates for Chesterfield 7 and Bremo 3 represent recent Virginia Power long range forecasts (Ellis, 1989). The contract heat rate for Multitrade is 12,986 Btu/kWh (Article 10.2). Capacity factors in the 50-60% range are approximately at the boundary of baseload and intermediate load generation.

1.2.9 Paulsboro and Vista Limited Partnerships

These two projects are identical coal-fired facilities sited at a common location that were recently awarded contracts in the JCPL solicitation discussed in Section 1.1.3 above. Each project involves contract capacity of 100 MW due in commercial operation by May 31, 1994. The sponsors of these projects are a joint venture of Mission Energy and the Fluor/Daniel engineering consortium. Technically each joint venturer is the owner of one facility and the minority partner of the other. The actual facilities are rated at 158 MW in each case, but only 100 MW from each partnership will be sold to JCPL. The remaining capacity is being marketed to other utilities in New Jersey.

The pricing terms for Paulsboro and Vista are identical, and more in line with conventional baseload configurations. The fixed and variable costs are quoted in the contract in 1987 dollars, so they require some adjustment for expression as nominal prices when the plant goes into commercial operation. The fixed costs have two components. A levelized annual cost of $208.61/kW-yr charged every year. A fixed O&M charge of $81.75/kW-yr is specified to escalate with the GNP Deflator. If we assume a 5% annual escalation in this index over the seven year period from 1987 to 1994, then the O&M fixed cost will be $115.03/kW-yr, for a total cost of $323.64/kW-yr. The variable cost in 1987 is $0.14909/kWh; this cost is also indexed to the GNP deflator. Under the same escalation assumptions, the 1994 price would be $0.02098/kWh.

The projects offer dispatch conditions that resemble the Doswell contract; commitability, but limited curtailment. The contracts specify minimum run times of 24 hours and minimum down times of 4 hours. The output range, however, is only from 80 MW to 100 MW; exactly the same limitation as in Doswell. The pricing formula also includes payments for "Eligible Start Ups." The price is $35,320 per start (1987$), indexed to the GNP deflator. An "Eligible Start Up" (defined in Article 3.1(b)) includes all starts except those following a forced outage, or when the facility is selling electricity to another electric utility. We observed that the JCPL bid evaluation system included start-up costs in the estimated bid price by using an ex ante forecast of the number of starts/year. Since these projects have quite low variable costs, the JCPL system predicts a very low number of starts per year. For the 86% annual capacity factor forecast for these projects, the prediction is 20-25 starts/year. Our discussion in Section 4.2 below will suggest that even this estimate is too high.

These projects have a mild version of the priority service feature which characterized the TECO Power Services contract. In this case, JCPL has exclusive call on the 100 MW of contract capacity per project. The remaining capacity, estimated at 60 MW per project can be sold on a firm or economy basis to other utilities. The capacity dedicated to JCPL will presumably be available on a spot basis to others when JCPL has not placed a call for it. Given the low variable price of power from these projects, it is unclear whether there will be many opportunities to resell the "second call" output.

1.2.10 AES Shady Point

This project is a dispatchable coal-fired facility of approximately 300 MW whose output will be purchased by Oklahoma Gas and Electric Company (OG&E). The project's contract was signed in 1985, and does not represent the outcome of competitive bidding. Therefore the pricing terms are not comparable to most of the projects previously discussed. The contract language strongly suggests a "proxy plant" approach that pays to the qualifying facility a revenue stream that resembles utility cost recovery patterns. Pricing is divided into three phases: (1) before 1/1/91, (2) calendar years 1992 and 1993, and (3) 1993-2022. Phase 3 is based on the costs of an "avoided coal plant," which the contract characterizes as similar to OG&E's Muskogee 6 unit, except with scrubbers.

The capacity payments in Phase 3 are shown in detail in Table 1-5. The annual payment consists of the sum of three terms, a Base price, a Fixed O&M price, and an Adjustment term. The sum shows something like the characteristic rate-of-return on depreciating rate base pattern. The annual costs start high and get lower over time. The table shows 30 year present values for the capacity payments discounted at 10% and at 20%. The annual annuity for this stream at 10% is $405/kW-yr, and at 20% it is $434/kW-yr. These prices are clearly higher than comparable prices in contracts that have resulted from competitive bidding. Energy payments in Phase 3 are based on a contract heat rate of 10,500 Btu/kWh times the OG&E cost of coal. In addition there is a variable O&M payment of $0.00236/Kwh (1985 $), which is indexed to the Producer Price Index.

The facility will be dispatched by OG&E with the objective of achieving a 65% annual capacity factor. The utility will have the flexibility to curtail the unit to 35% of its capacity, but there is no provision for actual shut-down and start-up. There is no mention of explicit constraints on ramp rates. The contract also contains a clause which gives AES Shady Point "dispatch priority over all subsequent qualifying facilities which are technically capable of operating in a dispatchable mode but are not operated on a dispatchable basis (Section 2.6(d))."

1.3 Summary and Conclusions

This section has reviewed developments in competitive bidding from two perspectives; the structure of RFPs used by buyers, and the contracts which have emerged from the process. The RFPs have gotten less explicit over time about how utilities will evaluate bids. The contracts are quite explicit about pricing and operating conditions.

Broadly speaking, there is abundant competition. Therefore, utilities can afford to be selective. This is reflected in both the increasing lack of explicit and detailed evaluation criteria, and in the number of constraints that are being imposed on bidders. For example, the FPL requirements on termination place substantial performance risks on bidders. Another example, which we take up in Section 4, is the VP preference for low minimum operating levels on baseload and intermediate plant.

As the market broadens, however, the transmission issue is coming into increasing prominence. This issue cuts both ways. On the one hand, utilities such as VP and FPL make clear that they will not provide bidders sponsoring "out-of-control-area" projects with wheeling assistance. In other cases, notably SMUD and PSI, such assistance will be offered. In these latter cases, the buyer recognizes a dependence of potentially good bids on the availability of transmission services. The LADWP RFP is somewhere in the middle. This utility has an extensive, multi-state

Table 1-5

AES Shady Point Capacity Pricing 1993-2022 ($/kW)

Year	BASE	O&M	ADJ	SUM
1993	363	43	34	440
1994	363	45	36	444
1995	363	47	38	448
1996	363	50	40	453
1997	363	52	43	458
1998	363	55	45	463
1999	363	58	48	469
2000	363	61	51	475
2001	363	64	54	481
2002	363	67	57	487
2003	329	70	0	399
2004	329	74	0	403
2005	329	77	-27	379
2006	235	81	-32	284
2007	235	85	-38	282
2008	235	89	-44	280
2009	235	94	-50	279
2010	235	99	-57	277
2011	235	103	-64	274
2012	235	109	-72	272
2013	235	114	-80	269
2014	235	120	-89	266
2015	235	126	-98	263
2016	235	132	-107	260
2017	235	139	-118	256
2018	235	146	-128	253
2019	235	153	-140	248
2020	235	161	-152	244
2021	235	169	-165	239
2022	235	177	-179	233
NPV@10%	3092	647	79	3818
NPV@20%	1739	281	142	2162
Annual Levelized Cost @ 10%				405
Annual Levelized Cost @ 20%				434

Table 1-6: Contract Summary

Expected Operation	Project	MW	Buyer	Annual Fixed Cost	Unit Variable Cost	Type of Dispatch
7/92	Dartmouth	67	Commonwealth Electric (50 MW)	$308/kW (1/2 indexed GNP)	17.8 mills/kWh gas index	Baseload-curtailable
7/92	Enron	140	New England Power (58%)	$361/kW indexed	11.9 mills/kWh NEPOOL fossil fuel index	Baseload-curtailable
12/91	Doswell	600	Virginia Power	$123/kW for 15 yrs 71/kW for next 10	8470 Btu/kWh *VP Gas cost	Committable-20% curtailment only
1/93	TECO	295	Seminole/ Tampa Electric	$115/kW	CC (220 MW) and CT (75 MW) fuel cost	Complete flexibility priority service
3/92	Commonwealth Atlantic	240	Virginia Power	$63/kW	12,450 Btu/kWh *Fuel Cost (Gas-Summer Oil-Winter)	Peaking
3/94	Cogen	440-594	Consolidated Edison	$205/kW 1/3 indexed to GNP	26.34 mills/kWh gas index	Curtailment to 82% weekday 47% weekend
11/92	Multitrade	76	Virginia Power	$228/kW	26.5 mills/kWh coal index	Unlimited
5/94	Paulsboro/ Vista	2X 100	Jersey Central P&L	$290/kW (87$) 1/3 indexed to GNP	14.9 mills/kWh GNP index	Commitable-20% curtailment only
	AES Shady Point	300	Oklahoma G&E	$405/kW	10,500 Btu/kWh *Coal Cost	Curtailable to 35%

high voltage transmission system that is central to its system. Bidders must show impacts from their projects on this system as part of the bid.

On the seller's side, there is also increasing sophistication and product differentiation. Our review of contracts shows a great variety of both pricing structures and operating parameters. We have gas-fired projects (Dartmouth and Enron) that have a split of fixed and variable costs which resemble coal. Conversely, Multitrade is a coal project with a pricing structure that in the short run looks like the gas-fired Cogen project. On the operations side, the variety of features and constraints makes it very clear that the term "dispatchability" is very broad indeed. Some projects offer commitment (i.e. start-up and shut-down flexibility), but very little curtailment (Doswell and Vista/Paulsboro). Others offer curtailment, but no commitment (Cogen and AES Shady Point). In cases where projects will have output sold to multiple buyers, there is an explicit or implicit priority service.

In the following sections, we will explore analytically a number of the issues raised here. The price scoring approach adopted by JCPL (Section 1.1.3) is reviewed in detail in Section 2. Front-loading security, required of projects in many cases (Dartmouth and Cogen, for example) is reviewed in Section 3. The menu of dispatchability features is examined in Section 4.

2. DIFFERENTIAL AND RATIO SCORING METHODS

2.1. Introduction

This section discusses price scoring procedures for dispatchable projects. We will define dispatchability only in the broadest possible terms here. Section 4 goes into substantial detail that will not yet be necessary for our purposes. For this discussion all we need to know is that dispatchable plants will operate for a variable amount of time during the year. The qualitative terminology of dispatch types makes this distinction. The term baseload refers to plants with low variable costs that typically run as much as possible. At the opposite extreme, peaking plants serve only the highest loads that occur for relatively few hours of the year. In between these extremes, intermediate load or cycling plants serve less than baseload and more than peaking. We show here that once the bidding system allows for dispatchability, simple price scoring techniques must be modified. In particular, we show that measuring the value of dispatchable projects as a percentage of a benchmark avoided cost is a serious distortion. Many bidding systems with self-scoring evaluation procedures use the percentage of avoided cost notion. We show that this creates a bias against baseload projects, everything else equal.

We use the term "ratio scoring" interchangeably with "percentage of avoided cost." Ratio scoring is perfectly acceptable when all bidders are offering baseload projects. Indeed, this was the original context in which competitive bidding for electric power arose. But once dispatchability becomes an intrinsic feature of the bidding, ratio scoring undervalues the baseload bid. As the discussion in Sections 1.1.2 and 1.1.5 (Virginia Power and Public Service of Indiana) indicate, many RFPs are explicit about the competition between baseload and peaking alternatives. We will illustrate the nature of the problem below with explicit examples that we argue are quite general. We show why the bias of ratio-scoring is a general result, and argue for what we call differential scores. This is just a way of expressing the value of a bid in units of "$ per kilowatt." The value will be measured as the difference between an appropriate avoided cost standard and the bid price.

Our analysis draws substantially from the ratio-scoring procedure proposed in the Jersey Central Power and Light (Section 1.1.3). This procedure is the most explicit treatment of dispatchability among the self-scoring RFPs. The treatment carefully assigns different avoided costs to bids depending on how they would be dispatched. Ratio scoring, however, is mandated in New Jersey in the "Stipulation of Settlement" (NJBPU, 1988), which defined the broad framework under which competitive bidding would be organized in that state. This stipulation contains no explicit discussion of dispatchability, so apparently the problem we identify was not discussed when these ground rules were formulated. Our argument does not depend upon the precise structure of the Jersey Central Power and Light (JCPL) procedure. In fact, we only follow its qualitative outlines. In our detailed examples we derive independently the notion of an "avoided cost price" which is implicit in the JCPL approach. Our framework allows a rigorous derivation of the bias in ratio scoring. This section is organized as follows. In Section 2.2 we give preliminary definitions, our first example, and draw the analogies to the JCPL procedure. Section 2.3 shows how the result generalizes. Section 2.4 gives input and output details underlying the initial example. Section 2.5 shows qualitatively how the computations are made. Finally Section 2.6 gives an example of the phenomenon using the JCPL technique. Mathematical derivations are given in Appendix A.

2.2. A Simple Example of the Ratio Scoring Problem

2.2.1. Avoided Cost

When a utility purchases generating capacity, either under standard PURPA arrangements, or through a public auction, it is standard practice first to evaluate the alternative cost of power generation. Determining this requires a choice of technology if new capacity is to be constructed, or the choice of a supplier, such as a power pool, if power is to be purchased in a spot market. In either case, there will be certain fixed and variable costs associated with the "internal" power source, and this will determine its loading order and the cost of internally generated (or purchased) power. We call this the total internal power cost.

When a bid of a certain capacity is being evaluated, the utility will determine a new loading order that avoids the use of some previously needed internal capacity, and compute a total "with-bid" power cost. If this computation is done *without* including the cost of the bid-supplied power, then the difference between the total internal power cost and the total "with-bid" power cost is know as the *avoided cost* of power for the bid under consideration. Clearly, and this is a central point of this chapter, the avoided cost minus the cost of power purchased under the accepted bid, is the savings attributable to accepting that bid. Formally we express this as follows:

$$\textit{Total Internal Cost} = \textit{Base system} + \textit{Alternate "Plant"} \qquad (2\text{-}1)$$

$$\textit{Avoided Cost} = \textit{Total Internal Cost} - \textit{"With-Bid" Cost @ ZERO BID \$} \qquad (2\text{-}2)$$

$$\textit{Savings} \ = \ \textit{Avoided Cost} \ - \ \textit{Bid Cost} \qquad (2\text{-}3)$$

Since bids involving a greater capacity will, *ceteris paribus*, show both a proportionally greater avoided cost and cost of supplied power, it would be a mistake to compare bids without adjusting for the bid's capacity. This is done simply by dividing both costs by the bid's capacity, so that, avoided cost, cost, and savings are all expressed in dollars per kilowatt ($/kW). Having said this, we would like to present an example of two hypothetical bids that have been carefully modeled to reflect a typical bid for base-load generation and a typical bid for peak-load generation. These have been embedded in the framework of a hypothetical, but again realistically modeled utility.

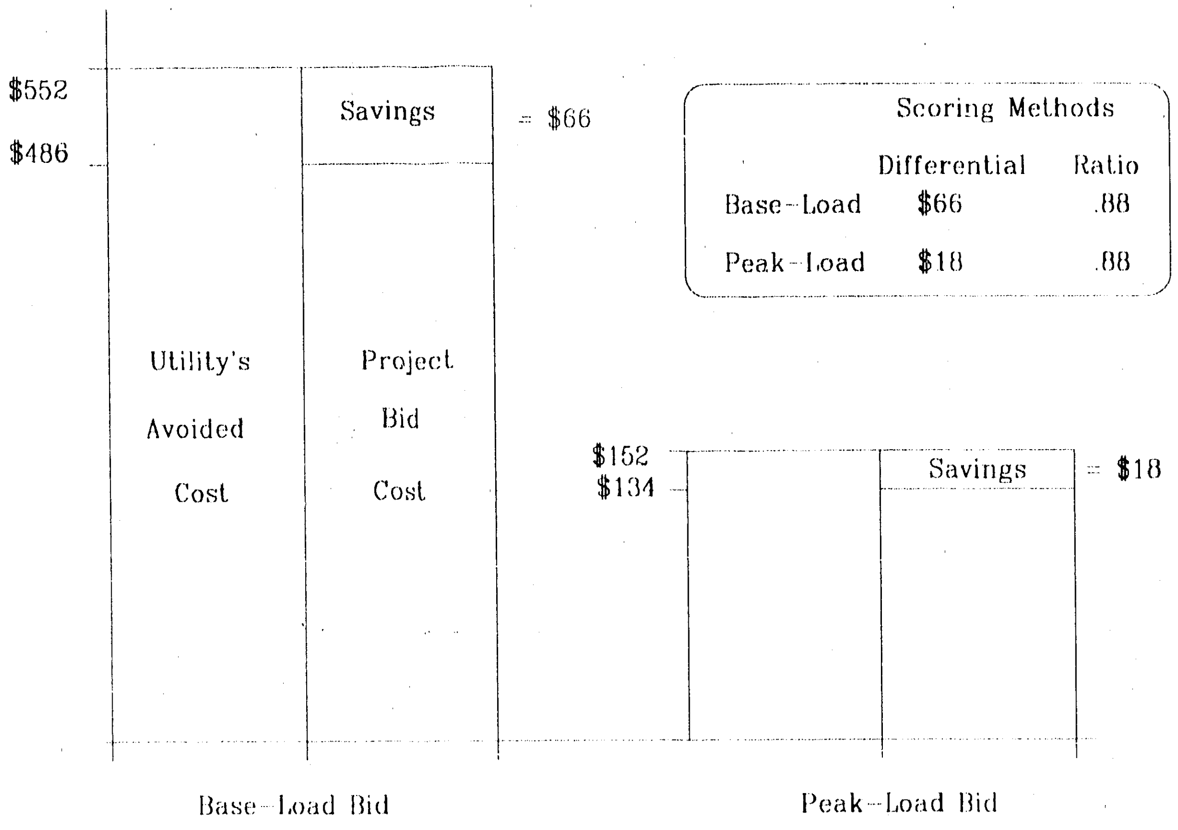
The results of our modeling, indicating the avoided costs and bid costs are shown in Figure 2-1. Note that the figures are all for one calendar year, but are based on fixed and variable costs that have been levelized over the lifetime of the bid, so these costs effectively represent the entire bid.

2.2.2. The Two Scoring Methods: Ratio and Differential

There are two obvious ways to score a bid given its avoided cost (ac) and its bid cost (c); one can form the difference $ac - c$ or the ratio $c\,/\,ac$. (Although $c\,/\,ac$ declines with desirability of a bid, it is first computed and can then be manipulated to give a score that increases with the desirability of a bid.) Though the differential score is the more obvious choice, the ratio score has a certain appeal to it, and may have developed as a way to normalize for project size in a system where ac and c were not normalized to a per-kW basis. If the costs were not normalized, the ratio score would be clearly superior. It will also shortly be seen that in the context of simple PURPA implementation, where all projects exercise the obligation to have output purchased and therefore are must-run, the bias that can be introduced by the ratio score would not occur. Thus in this kind of PURPA environment, and when un-normalized costs are used, the ratio score would be correct and superior to a difference approach.

Be that as it may, in the present environment, where base-load and peak-load bids are competing in the same auctions, the differential score, using normalized costs, is demonstrably superior to any version of the ratio score. This is most easily seen from the graph of our present example which can be found in Figure 2-1. Because base load units run much more than peak-load units, the two scores give quite different answers. From this figure we see that bids with greater avoided cost and bid cost but the same ratio score will provide greater savings. That is savings is exactly measured by the differential score. In general, base-load bids will have greater *ac* and *c*, so it is these bids that will be discriminated against.

Figure 2-1. Differential Price Scores (Levelized $/kW-yr) Accurately Reflect Value to Ratepayers



In summary, we can say that the difference score measures exactly how much a project saves per year, while the ratio score indicates how much a project is saving per hour *for the hours that is is running*. Because the ratio score does not give credit for the hours run it is biased agains base load bids.

2.2.3. The JCPL Method

The JCPL method defines an avoided cost corresponding to a particular bid cost using a series of look-up tables. The essence of these tables is an explicit linkage between the energy price that is bid, the number of hours a project could be expected to operate at that price, and an avoided cost for that number of operating hours. On the fixed cost side the comparison is much simpler, there is a time pattern of annual avoided capacity costs and a time pattern of bid costs. Total avoided cost is the sum of the energy and capacity terms. Total bid cost is the sum of energy price bid times the number of operating hours plus the fixed cost. The ratio score is equivalent to calculating an average cost per kWh. Since both the numerator and the denominator have the same number of operating hours, we can imagine that total cost is divided by operating hours before taking the ratio. We refer to this $/kWh average in the case of avoided cost as an "avoided cost price." For peaking projects this avoided cost price is higher than for baseload projects. In a world of "must-take" baseload projects there would be very small differences among the avoided cost prices associated with different projects. Therefore the term "avoided cost" can be used interchangeably to refer to either the unit price or the total cost of the purchase. Where operating hours vary drastically among projects, this imprecision is no longer tolerable. JCPL's method of developing an avoided cost per kWh that is unique to each project's variable price is an important refinement that is fundamental to comparing bids from plants of varying characteristics -- peaking, intermediate and baseload.

After computing an avoided cost corresponding to each project's bid price, JCPL's method goes on to compute the ratio of bid price to that avoided cost, and derives a price score from this ratio. The spreadsheet used by JCPL to compute the ratio score contains the information to compute the differential score. As argued above, a meaningful differential score should be normalized to capacity, i.e. "$/kW," so that large projects are not unfairly benefited versus smaller projects. Once a normalization to $/kW has been made, other elements of the bid evaluation process must also be made compatible. There are two ways this can be done, either (1) express non-price factors in dollar terms, or (2) convert the $/kW metric into a point system.

2.2.4. Conclusion

The ratio score, given by bid cost divided by avoided cost, fails to account for how much a project runs, and because of this is generally biased against base-load bids. In contrast, a scoring method based on the difference between avoided cost and bid cost, will account for the *total* saving provided by a bid. As can be seen from the above realistic example, the bias can be very significant.

2.3. Generality of Our Conclusions

The conclusions stated at the end of the last section are fairly unqualified and somewhat loosely stated. In this section we will refine those conclusions, and specify any qualifications. Fortunately, the precise version will turn out to be very general and the qualifications minimal, in other words, the intuitive approach pursued so far will turn out to be completely supported by a more rigorous mathematical approach.

2.3.1. A Result Based on Total Cost

From Figure 2-1, it is clear that the savings to the ratepayer depends both on the ratio score and on the project bid cost. If two bids have the same ratio score, then the one that costs more will also save more. This is a simple consequence of the arithmetic that is apparent in Figure 2-1, and spelled out algebraically here.

Consider two bids with the same ratio score; that is:

$$\frac{c_1}{ac_1} = \frac{c_2}{ac_2}$$

Two bids with the same ratio score are likely not to have the same difference score, so let us call the one with the greater difference score bid 1. We now investigate what it is that will cause this greater difference score, dc, when the ratio scores are equal.

$$dc_1 > dc_2$$

holds if and only if

$$ac_1 - c_1 > ac_2 - c_2,$$

which holds if and only if

$$ac_1 \cdot (1 - \frac{c_1}{ac_1}) > ac_2 \cdot (1 - \frac{c_2}{ac_2}).$$

Now assuming that the the ratio score is less than one, so that the term in parenthesis is positive, we see that because the ratio scores are the same, the last equation is true if and only if

$$ac_1 > ac_2,$$

which is equivalent to

$$c_1 > c_2.$$

This proves our first result.

If two bids have the same ratio score and it is less than 1,
then the bid that costs more per unit of capacity
will have the greater differential cost and should be preferred.

2.3.2. High Total Cost Bids Are Baseload

Remember that the higher cost is mostly associated with a greater capacity factor and thus with greater use. Since savings is proportional to use, the initial result is not counter intuitive. Now while this result is perfectly general, it does not quite close the discussion.

We have not yet translated the analysis into the language of peaking and base-load bids. In our previous discussion we tacitly assumed that bids with greater total annual cost would employ base-load technology, while bids with lower total cost would employ peaking load technology. Of course this is generally the case because base-load bids have greater capital cost and are run for more hours per year. However there is one factor, and that is fuel costs, that tends to make base-load cheaper, so it will take a more careful analysis to prove that our first statement in terms of annual cost, can be translated into a statement about base-load versus peaking load bids.

Base-load bids, by definition, have lower energy charges than peak-load bids. This is why they are placed earlier in the loading schedule. Is it possible for a bid with a lower energy charge, but with the same ratio score, to accrue a lower annual cost? In Appendix A we prove that the answer is no, but here we must be satisfied with partial intuition. What we can see clearly is that a bid with a lower energy charge but with the same value (i.e., differential score) cannot accrue a lower annual cost. This is simply due to the fact that, as was just noted, the lower energy cost bid will be run more, so if it costs less annually, it would have provided more power for less cost and so is clearly of more value. This does not quite answer the question of interest which concerns two bids that do not have the same value but do have the same ratio score. We now present the second rigorously stated result, whose full justification is found in Appendix A, comparing the two scoring methods.

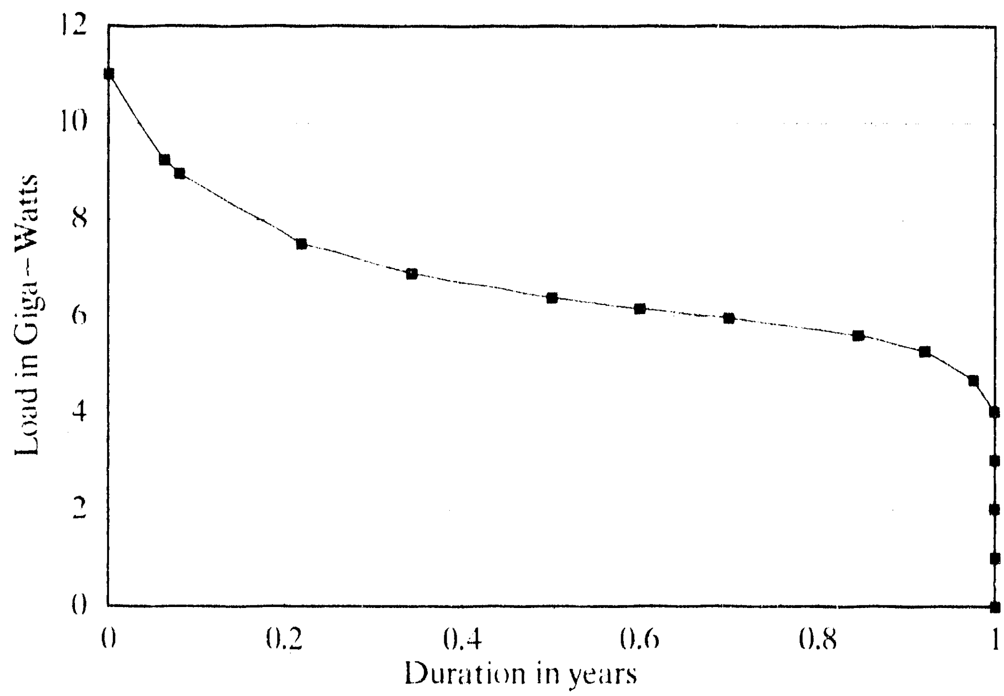
If two bids have the same ratio score and it is less than 1, then the one with the lower energy price will have the greater differential score and is to be preferred.

2.4. Complete Description of Example Input and Output

We have already cited an example (see Figure 2-1.), which we claimed was more or less true to life, to demonstrate the importance of the difference between the two scoring systems. We now present the example in detail, both its assumptions and conclusions, however we will leave the underlying calculations to the Appendix. We will also present data on "avoided price" and "project bid price", the values that are computed by Jersey Central for use in their calculation of the ratio score.

Our example begins with a description of a utility before the auction is held. This includes a load duration curve, see Figure 2-2, and a loading schedule, see Figure 2-3, which shows at what load le 'el a plant with any given variable (energy) price will be dispatched.

Figure 2-2. Load-Duration Curve



Next we must describe the competing bids, all of which we construct to receive the same ratio score. A bid, in this example will consist simply of a variable (energy) cost and a fixed (capital) cost. The variable cost together with the loading schedule determines a duration for each bid. Table 2-1 displays this data for three bids, and also for the utility's avoided technology with which they will be compared in order to establish avoided cost.

Figure 2-3. Loading Schedule

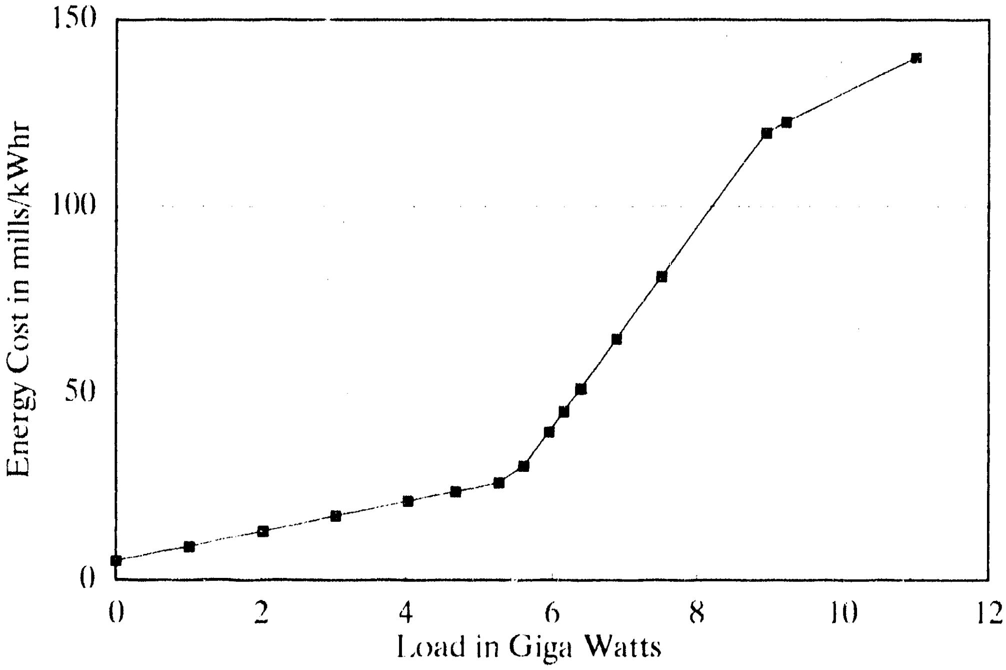


Table 2-1. Variable Cost, Fixed Cost, and Durations of Bids			
	Annual Energy Cost mills/kWh	Fixed Cost $/kW	Duration hours
Avoided	123	64	560
Peak-Bid	120	57	700
Intermediate-Bid	65	160	3000
Base-Bid	30	315	7400

These three bids were specified to approximate pricing features we identified in the discussion of contracts (Section 1.2 above). The baseload bid resembles Vista/Paulsboro (see Section 1.2.9 above), which were actual winners in the JCPL solicitation. The intermediate bid resembles Doswell (see Section 1.2.4 above), although with some adjustment. The peaking bid resembles Commonwealth Atlantic (see Section 1.2.6 above). To adapt our somewhat static framework to a long run planning perspective we work with levelized variable costs. Bids then have two dimensions, a levelized fixed cost and a levelized variable cost. We assume real cost escalation of oil and natural gas fuels of about 1.6%/year, and zero real cost increases for coal. This difference in fuel cost escalation rates accounts for the steep slope on the upper portion of the variable cost curve in Figure 2-3.

We assume that the bids represent conditions in approximately 1993, and estimate what the indexed cost of key parameters would be at that time. For Vista/Paulsboro (which would not actually operate until May 1994) this means a variable cost that is about 25% greater than the price quoted in 1987 $, i.e., 18.7 mills/kWh. The twenty year levelized equivalent at zero real escalation would be 30 mills/kWh. The fixed cost corresponding to the same escalation would be $315/kW-yr. The assumed dispatch is 7400 hours per year. For the intermediate load plant we assume that gas commodity costs are $4/MMBtu, and that the plant heat rate is 8500 Btu/kWh (the Doswell contract heat rate). This gives a 1993 variable cost of 34 mills/kWh. The levelized equivalent at 1.6% annual real escalation is 65 mills/kWh. The assumed fixed cost is $160/kW-yr. This value is about 30% greater than the capacity payment in the Doswell contract. That contract allows for other fixed cost collection including gas transportation demand charges and gas storage and inventory costs. The dispatch is assumed to be 3000 hours per year.

Finally, the peaking plant is assumed to burn distillate oil at all times at a 1993 cost of $5/MMBtu. The heat rate is 12,500 Btu/kWh, which is approximately the Commonwealth Atlantic contract heat rate. These parameters yield a 1993 variable cost of 63 mills/kWh. With 1.6% real escalation, this is equivalent to a levelized cost of 120 mills/kWh. On the fixed cost side we assume $56.50/kW-yr, which is also approximately the Commonwealth Atlantic fixed cost. The dispatch is assumed to be 700 hours per year.

This completes the description of the model assumptions. From these assumptions we carried out standard calculations of avoided cost, where each bid has an avoided cost that is tied to its expected operating hours and variable cost. We make only one approximation which is based on the assumption that bid size is small when compared with the size of the utility. We feel that this assumption is quite accurate, and that the result would hold qualitatively even if this were not the case. The calculations are detailed in the Appendices, but here we will present only the results. The bottom two lines of Table 2-2 give the two scores under consideration. As can be seen, the ratio score is the same (.91) for all three bids, while the differential score varies considerably.

One more variable can be computed from our example; this is avoided variable cost per kWh supplied. We have also called this the "avoided price" because it is measured in mills/kWh, but it is important to remember that it does not act as a price since it is only valid for a single quantity, which is determined by the optimal loading schedule. This variable is crucial to employing Jersey Central's approach to scoring if we want to follow their method literally. Below we present a graph (Figure 2-7) of both variable energy price and avoided price (the 2-curve graph), together these can be used as follows. Take a bid's variable energy price and use it with the energy price curve to read off the bid's duration. Then at that duration, read off the bid's avoided price. Now multiply both prices by the bid's duration to find the bid's variable

Table 2-2. Example Outputs for Three Representative Bids			
	Base-Load	Intermediate	Peaking
variable energy price	30.481	64.6	119.7
variable energy cost	226	194	84
annual fixed cost	315	160	57
annual total cost	541	354	140
avoided variable cost	527	324	90
avoided fixed cost	64	64	64
avoided total cost	591	388	154
differential variable cost	302	130	6
differential fixed cost	-251	-96	8
differential total cost	51	34	13
(total cost)/(avoided total cost)	0.91	0.91	0.91

energy cost, and avoided cost. After these are added to the bid's fixed cost and the avoided fixed cost, we can take either their ratio or the difference and compute one score or the other.

For our example, the avoided cost price is calculated by dividing for each bid its total avoided cost (in units of \$/kW-yr) by its dispatch hours. For the baseload bid this yields 7.98 cents/kWh. For the intermediate load bid it is 12.93 cents/kWh. And for the peaking bid it is 22 cents/kWh.

2.5. The Method Used to Compute the Example

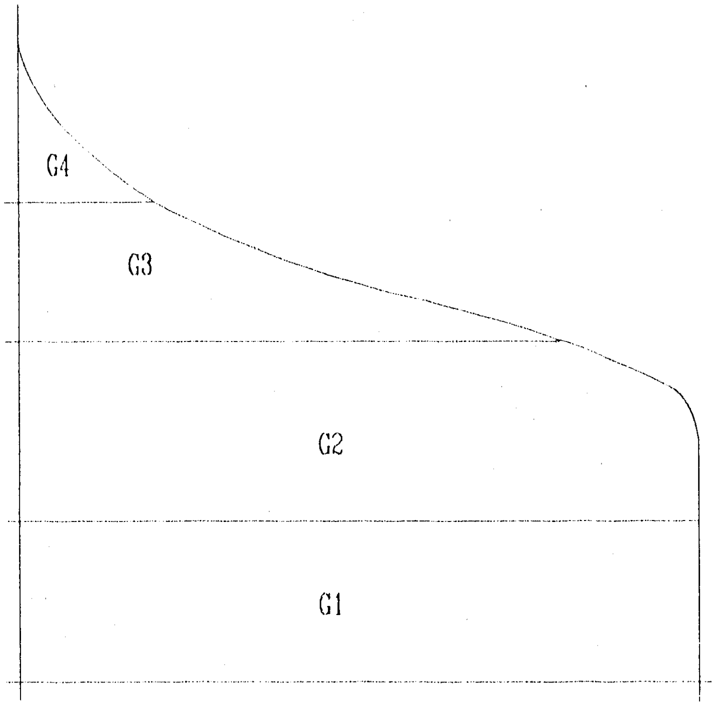
Although derivation of the equations used to compute the example results will be reserved for the Appendix, the basic approach can be motivated and illuminated by the use of a few simple graphs (Figures 2-5 and 2-6). The most difficult and interesting part of the process, is the calculation of avoided variable cost, so we begin with that.

2.5.1. The Calculation of Avoided Variable Cost

For simplicity we will consider the case where the avoided technology has an energy price as great as any technology used by the utility. Figure 2-4 shows the utilities load-duration curve as it would be it it supplied its power needs with avoided technology and without accepting the bid we are considering. The vertical load-axis and the area under the curve is divided according to the energy cost of the technology used to generate that part of the load.

As a first example of an avoided cost calculation, let us consider a must-run bid, one that would be loaded at the very bottom of the loading order. That bid can be thought of as effectively shifting up the loading-schedule making unnecessary some of the power generation previously supplied by the utility's capacity. Just above the load-duration curve is a region depicted in Figure 2-5 that represents power generation that is no longer needed. This region is bounded above by a dotted line that is the same shape as the load-duration curve, but higher than it by exactly the generating capacity of the bid. Within the region between the two parallel curves is

Figure 2-4. Pre-bid Load-Duration Curve



the avoided power that gives rise to the avoided cost. To calculate this cost one must multiply the area of each sub-region by the appropriate energy price and sum the results.

Now we must analyze the slightly more complex cases of the avoided costs of intermediate and peaking technologies. These can also be viewed as shifting up parts of the loading schedule, but only the part of it with energy price greater than that of the bid under consideration. This is shown in Figure 2-6. What is now clear is that while avoided energy cost/kWh increases, the total avoided cost decreases as we move from base to peak technology. For each duration we can find a corresponding energy price and from this and the load duration curve we can calculate an avoided cost per kilowatt of capacity. If this avoided cost is divided by the duration in hours, we have the avoided price used by Jersey Central. We can now plot both energy price and avoided price against duration to give us Figure 2-7.

Next we compute the two scores. As explained above, avoided variable cost (*avc*) can be calculated from the loading schedule and the load-duration curve. By subtracting the annual variable (energy) cost of the bid (*vc*) we can find the differential variable cost (*dvc*).

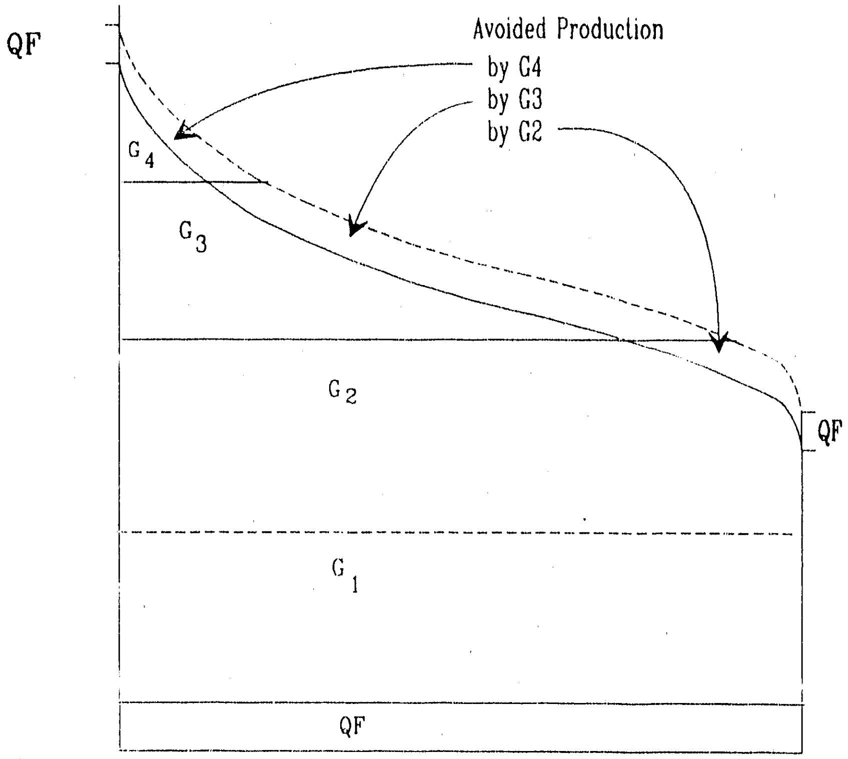
$$dvc = avc - vc \qquad (2\text{-}4)$$

Total differential cost is just differential variable cost plus differential fixed cost, which is simply the difference between the capital cost of one kW of avoided technology and of one kW of bid technology.

$$differential\ score = dc = dvc + dfc \qquad (2\text{-}5)$$

this completes the calculation of the differential score, which is simply differential cost. We now turn to the calculation of the ratio score.

Figure 2-5. Calculating Avoided Cost



$$\text{AVOIDED COST } (\$) = \text{AVC } (G_2) + \text{AVC } (G_3) + \text{AVC } (G_4)$$

$$\underset{\text{(cents/kwh)}}{\text{Avoided Cost Price}} = \frac{\text{Avoided Cost}}{\text{QF MW} * t}$$

Total avoided cost (ac) is just avoided variable cost plus avoided fixed cost, where avoided fixed cost is again the cost of one kW of avoided technology.

$$ac = afc + avc \tag{2-6}$$

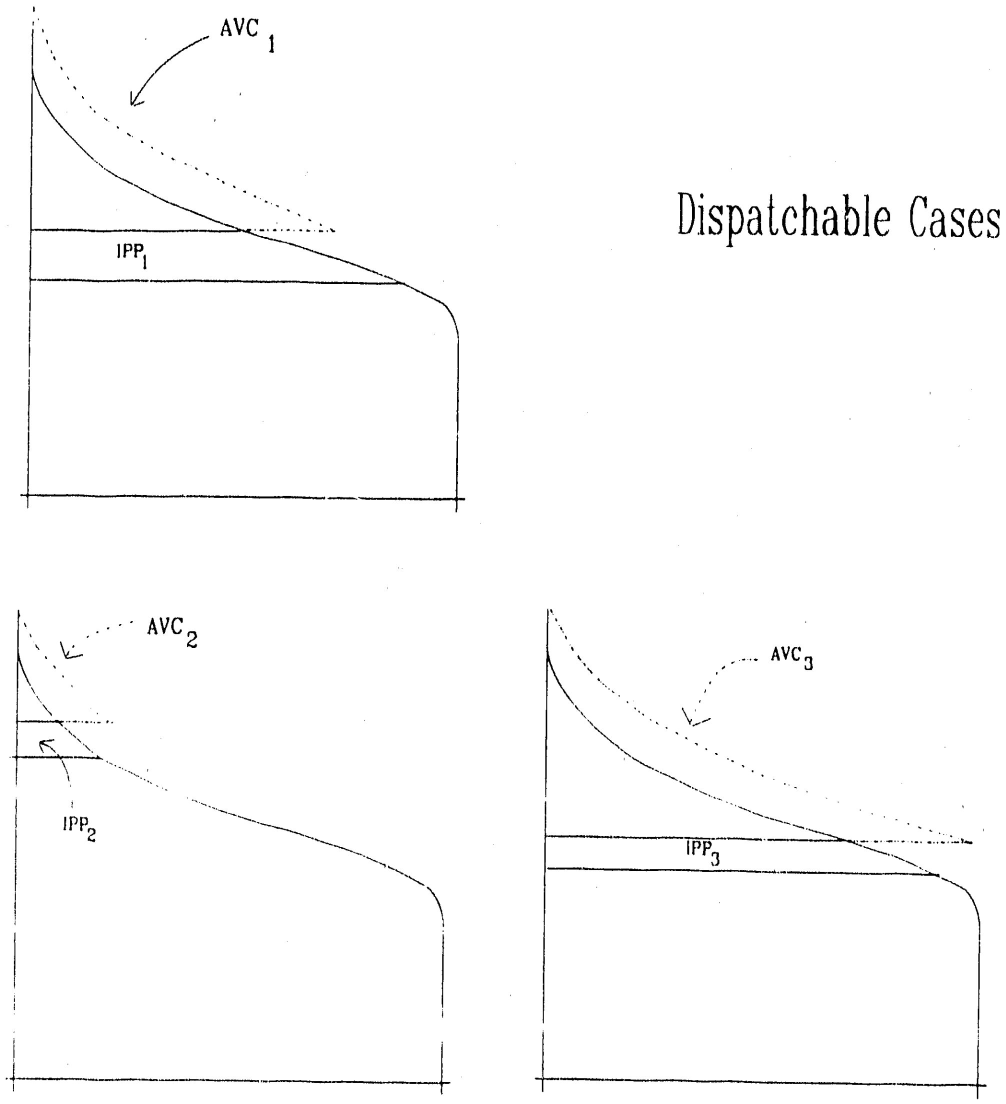
Total bid cost is just annual energy cost plus the annual cost of one kW of bid capacity. The ratio score is simply bid cost over avoided cost.

$$ratio\ score = c \,/\, ac \tag{2-7}$$

2.6. Example Using JCPL Spreadsheet

Finally, we include an example using the actual spreadsheet that accompanied the JCPL RFP. This spreadsheet is quite large and its outputs are substantial. It performs the calculations outlined above for three price scenarios (with an on-peak and off-peak load duration curve and avoided cost price curve for each year of a twenty year forecast) and includes other calculations associated with front loading. We reproduce two output pages for each bid, each associated with the medium price scenario. On the first pages of the output (Tables 2-3a and 2-4a, labelled "Scoring Table 5M-Dispatchable) the avoided cost price for each bid is listed (for On-Peak and Off-Peak periods) for each year on the left hand columns, which is under the heading, "Buyer's Energy Avoided Costs Dispatchable." The remaining columns are total annual costs and

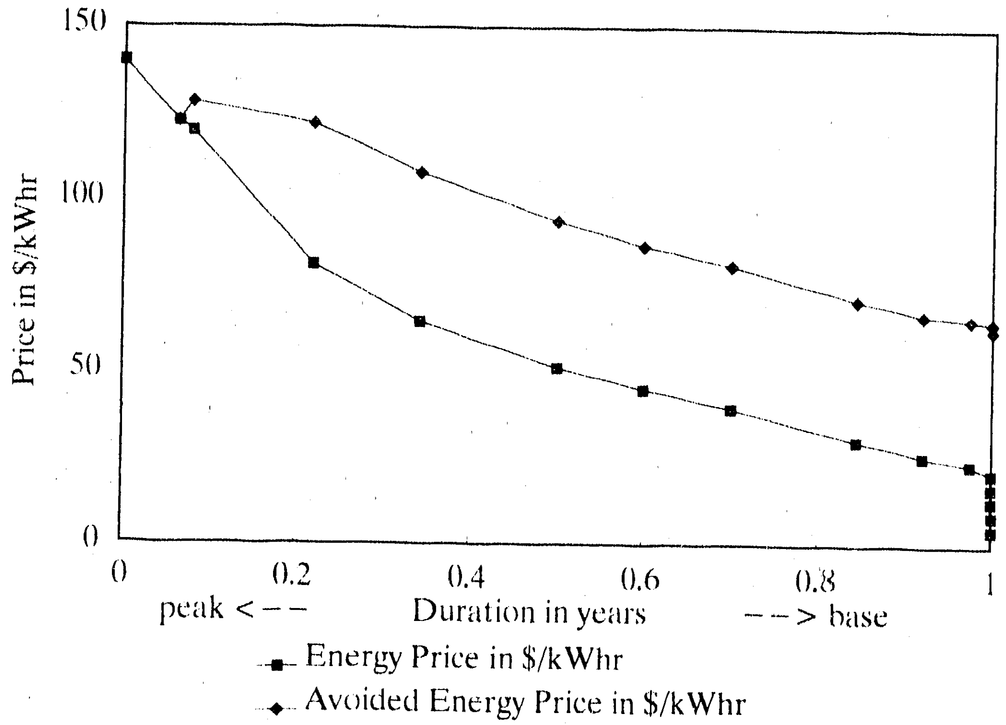
Figure 2-6. Avoided Cost of Non-Baseload Bids



payments. Scoring information is shown at the bottom underneath the boxed table. Lines [15] [16] and [17] are the relevant totals. Total Avoided Cost (present value) is [15] and Total Payments is [16]. The ratio score is [17]. The difference score is [15] - [16]. We also include second tables for each bid that is more disaggregated and that verifies input parameters. These pages are labelled "Scoring Table 4M - Dispatchable," Tables 2-3b and 2-4b. They show bid prices, dispatch duration and avoided cost prices.

We construct two stylized bids that are chosen to produce the same ratio score. One is a baseload coal project, the other is a gas-fired combustion turbine. Each is 100 MW of capacity. We show that the baseload project has a greater differential score. The coal project starts in 1991, has a levelized annual capacity price of $210/kW and an energy cost of 24.4 mills/kWh. The energy price escalates at the rate forecasted by JCPL. Tables 2-3a and b show its score and production. The present value avoided cost is $241.7 million and the present value bid payment is $224.5 million. This produces a ratio score of 0.929 and a difference score of $17.2 million. Tables 2-3a and 2-4a show results for the gas-fired turbine. It has a 1991 start, a levelized fixed

Figure 2-7. Jersey Central Type 2-Curve Diagram



cost of $45/kW-yr and an energy cost of $36.17 mills/kWh. The energy price escalates each year with the gas price forecast assumed by JCPL. The present value avoided cost is $189.8 million, and the present value bid price is $176.3 million. This produces a ratio score of 0.929 and a difference score of $13.5 million.

These calculations show once more the theme of this section, ratio scoring for dispatchable projects undervalues the baseload project. In this example, the baseload project produces benefits that are 25% greater than the peaking project even though both bids are at 92.9% of avoided cost. Thus our previous result is confirmed again.

2.7 Differential Scoring Will Select Peaking Bids When They Are Economic

Finally, we address the potential concern that differential scoring might give too much emphasis to dispatch duration and therefore always select baseload bids because they operate for many hours. This concern is misplaced. We illustrate the flexibility and accuracy of differential scoring by modifying the duration parameters in our detailed example in Section 2.4. We want to modify them in a way that adjusts the economics of the variable cost structure from a case where baseload bids are desirable to one where they are less desirable. This would be a system with sufficient baseload power, or even too much baseload.

A baseload sufficiency, or excess, would be represented by a shift to the right of the loading schedule in Figure 2-3. Such a shift means that even at high loads the variable costs of operation are relatively low. In the extreme baseload excess case, resources that were intended for baseload would be serving intermediate or even some peaking requirements. Therefore, in evaluating dispatchable bids, we would expect that the hours of operation in this situation would decrease for the same prices, compared to our initial characterization.

Table 2-3a

SELLER'S PRICE AND COST PROJECTIONS

SCORING TABLE NO. 5M - DISPATCHABLE

CALENDAR YEAR	BUYER'S ENERGY AVOIDED COSTS DISPATCHABLE ON-PEAK ($/MWh) [1] FROM ATTACH-MENT A1M	OFF-PEAK ($/MWh) [2] FROM ATTACH-MENT A2M	BUYER'S CAPACITY AVOIDED COST ($/MW) [3] FROM ATTACH-MENT A4	BUYER'S COST AVOIDED (ANNUAL) (M $) [4] SEE NOTE (1) BELOW	BUYER'S PRESENT VALUE DISCOUNT FACTOR [5] [5] FROM TABLE 3M	PRESENT VALUE OF BUYER'S COST AVOIDED (M $) [6] [4]*[5]	"X" TIMES PRESENT VALUE OF BUYER'S COST AVOIDED (ANNUAL) (M $) [7] [6]*"X"	"X" OF BUYER'S COST AVOIDED LEVELIZED (M $) [8] SEE NOTE (2) BELOW	NON - LEVELIZED BALANCE - BUYER'S COST AVOIDED (ANNUAL) (M $) [9] [4] * (1 -"X")	REFERENCE PAYMENT SCHEDULE (M $) [10] [8]+[9]	BUYER'S PAYMENTS (ANNUAL) (M $) [11] [11] FROM TABLE 4M-DISPATCH.	PRESENT VALUE OF BUYER'S PAYMENTS (M $) [12] [11]*[5]	PAYMENTS IN EXCESS OF REFERENCE (M $) [13] [11]-[10]	CUMULATIVE PAYMENTS IN EXCESS OF REFERENCE (M $) [14] CUMULATIVE OF [13]
1987	0.0	0.0	0	0.0	1.0000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988	0.0	0.0	0	0.0	0.8985	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1989	0.0	0.0	0	0.0	0.8073	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1990	0.0	0.0	0	0.0	0.7253	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	40.4	30.1	36448	17164.2	0.6517	11185.2	3914.8	14933.6	11156.7	26090.3	30017.5	19561.1	3927.2	3927.2
1992	43.9	31.0	19354	17294.3	0.5855	10125.7	3544.0	14933.6	11241.3	26174.9	31092.5	18204.5	4917.6	8844.7
1993	49.5	32.5	30441	21145.4	0.5261	11123.6	3893.3	14933.6	13744.5	28678.2	32414.1	17051.5	3735.9	12580.6
1994	57.0	35.5	63737	28225.4	0.4726	13340.5	4669.2	14933.6	18346.5	33280.1	33948.2	16045.4	668.1	13248.7
1995	64.6	38.7	97751	35383.3	0.4247	15025.8	5259.0	14933.6	22999.1	37932.8	35350.0	15011.6	-2582.8	10666.0
1996	73.9	43.2	112697	41175.2	0.3815	15710.1	5498.5	14933.6	26763.9	41697.5	36787.7	14036.1	-4909.8	5756.2
1997	79.0	48.0	110691	44472.0	0.3428	15245.3	5335.8	14933.6	28906.8	43840.4	38241.7	13109.5	-5598.8	157.4
1998	85.7	54.2	106413	48338.0	0.3080	14888.2	5210.9	14933.6	31419.7	46353.3	39698.7	12227.3	-6654.6	-6497.2
1999	87.7	59.6	102341	50799.1	0.2767	14057.7	4920.2	14933.6	33019.4	47953.1	41129.5	11381.8	-6823.6	-13320.8
2000	94.2	64.5	98404	54204.5	0.2486	13477.1	4717.0	14933.6	35232.9	50166.5	42648.1	10603.8	-7518.4	-20839.2
2001	100.0	69.5	94652	57369.1	0.2234	12815.8	4485.5	14933.6	37289.9	52223.5	44554.6	9953.1	-7668.9	-28508.1
2002	104.9	75.8	90961	61214.2	0.2007	12286.4	4300.2	14933.6	39789.2	54722.9	46776.3	9388.6	-7946.5	-36454.6
2003	109.6	82.4	87328	64575.1	0.1803	11645.1	4075.8	14933.6	41973.8	56907.5	48841.1	8807.7	-8066.3	-44521.0
2004	116.3	89.6	82751	68523.2	0.1620	11102.5	3885.9	14933.6	44540.1	59473.7	51043.5	8270.3	-8430.2	-52951.2
2005	122.3	98.7	80243	73853.8	0.1456	10751.3	3762.9	14933.6	48005.0	62938.6	53777.8	7828.7	-9160.8	-62112.0
2006	129.7	110.6	76836	79756.0	0.1308	10431.7	3651.1	14933.6	51841.4	66775.0	56329.8	7367.7	-10445.2	-72557.2
2007	138.3	121.1	73663	85348.1	0.1175	10029.8	3510.4	14933.6	55476.3	70409.9	59033.4	6937.4	-11376.5	-83933.8
2008	146.7	132.9	70920	91494.9	0.1056	9660.5	3381.2	14933.6	59471.7	74405.3	61991.0	6545.3	-12414.4	-96348.1
2009	156.5	146.9	68694	99424.5	0.0949	9431.9	3301.2	14933.6	64625.9	79559.5	65413.0	6205.4	-14146.5	-110494.6
2010	168.3	162.8	66916	109646.7	0.0852	9345.6	3271.0	14933.6	71270.3	86204.0	69564.5	5929.2	-16639.4	-127134.1
2011	0.0	0.0	0	0.0	0.0766	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.0	0.0	0	0.0	0.0688	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	0.0	0.0	0	0.0	0.0618	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0	0.0	0.0555	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0	0.0	0.0499	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

[15] FV OF BUYER'S DISPATCHABLE COSTS AVOIDED = SUM OF COL [6] ------- = 241679.7
[16] PV OF BUYER'S DISPATCHABLE PAYMENTS = SUM OF COL [12] ---------- = 224466.1
Difference = 17213.6
[17] DISPATCHABLE PRICE RATIO (MEDIAN) {MUST BE <1} = [16]/[15] ------ = 0.929
NOTE: IF [17] = < .25 THEN [17] MUST BE SET EQUAL TO .25

Where "X" equals .35 if Primary Fuel is Solid Fuel, or equals .20 if Primary Fuel is Oil & Gas.

[18] SCENARIO PRICE FACTOR (MEDIAN, DISPATCHABLE) = (1-[17])/.75 ----- = 0.095

NOTE: (1) [4] = (([1] * [3] FROM TABLE 4M - DISP.) + ([2] * [4] FROM TABLE 4M - DISP.) + ([3] * [15] FROM TABLE 4M - DISP.))/1000
NOTE: (2) [8] = SUM OF COL [7] FOR CONTRACT YEARS OF OPERATION / SUM OF COL [5] FOR CONTRACT YEARS OF OPERATION

Table 2-3b

JCP&L PROJECT PROPOSAL
PROJECT: __________Baseload

SELLER'S PROJECTIONS IN BUYER'S SCENARIO

SCORING TABLE NO. 4M - DISPATCHABLE

CALENDAR YEAR	VARIABLE ELECTRICITY PRICE PAID BY BUYER DISPATCHABLE		ESTIMATED ANNUAL ELECTRICITY SOLD TO BUYER DISPATCHABLE		ANNUAL ELECTRICITY PRODUCTION DISPATCHABLE	SELLER'S DISPATCHABLE ANNUAL ELECTRICAL OPERATING REVENUES					
						BUYER'S VARIABLE PAYMENTS TO SELLER					ELECTRIC OPERATING REVENUE
	ON-PEAK	OFF-PEAK	ON-PEAK	OFF-PEAK		ON-PEAK	OFF-PEAK	START-UPS	COST PER START-UP	BUYER'S FIXED PAYMENTS	
	($/MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(M $)	(M $)	(#)	(M $)	(M $)	(M $)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
			SEE ATTACH-MENT A1M	SEE ATTACH-MENT A2M	[3]+[4]	[1]*[3]/1000	[2]*[4]/1000	SEE ATTACH-MENT A3			[6]+[7]+[8]*[9]+[10]
1987	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
1988	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
1989	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
1990	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
1991	24.4	24.4	232320	137250	369570	5668.6	3348.9	134	0.000	21000.0	30017.5
1992	25.3	25.3	233574	164669	398243	5919.3	4173.1	108	0.000	21000.0	31092.5
1993	26.3	26.3	234675	199567	434242	6168.4	5245.6	76	0.000	21000.0	32414.1
1994	27.4	27.4	234675	238503	473178	6421.7	6526.5	48	0.000	21000.0	33948.2
1995	28.4	28.4	234675	269828	504503	6675.1	7674.9	40	0.000	21000.0	35350.0
1996	30.1	30.1	234675	290526	525201	7054.4	8733.3	35	0.000	21000.0	36787.7
1997	31.7	31.7	234675	309624	544299	7433.8	9807.9	30	0.000	21000.0	38241.7
1998	33.4	33.4	234675	324661	559336	7845.2	10853.5	26	0.000	21000.0	39698.7
1999	35.3	35.3	234675	335320	569995	8287.6	11841.9	23	0.000	21000.0	41129.5
2000	37.3	37.3	234675	345126	579801	8762.1	12886.0	20	0.000	21000.0	42648.1
2001	40.2	40.2	234675	351698	586373	9426.9	14127.7	19	0.000	21000.0	44554.6
2002	43.1	43.1	234675	362906	597581	10122.6	15653.7	16	0.000	21000.0	46776.3
2003	46.4	46.4	234675	365772	600447	10881.3	16959.9	15	0.000	21000.0	48841.1
2004	49.9	49.9	234675	367712	602387	11704.2	18339.3	14	0.000	21000.0	51043.5
2005	53.6	53.6	234675	376287	610962	12590.2	20187.6	12	0.000	21000.0	53777.8
2006	57.8	57.8	234675	376304	610979	13570.1	21759.7	12	0.000	21000.0	56329.8
2007	62.3	62.3	234675	376065	610740	14614.2	23419.2	12	0.000	21000.0	59033.4
2008	67.1	67.1	234675	375955	610630	15753.5	25237.5	12	0.000	21000.0	61991.0
2009	72.3	72.3	234675	380019	614694	16955.8	27457.2	11	0.000	21000.0	65413.0
2010	77.8	77.8	234675	389743	624418	18252.0	30312.5	9	0.000	21000.0	69564.5
2011	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
2012	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
2013	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
2014	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
2015	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0

		ALL HOURS		DISPATCHABLE ON-PEAK		DISPATCHABLE OFF-PEAK
[12] SELLER'S PROJECTED AVERAGE AVAILABILITY (%) ---------------------	[12]	75.0%				
SELLERS PROPOSED DISPATCHABLE MW(ISO) ON-PEAK [13] AND OFF-PEAK [14] -------------------------------			[13]	100.0	[14]	100.0
SELLERS PROPOSED DISPATCHABLE MW (SUMMER CONDITIONS) ON-PEAK [15] AND OFF-PEAK [16] -----------------			[15]	100.0	[16]	100.0

Table 2-4a

SELLER'S PRICE AND COST PROJECTIONS

SCORING TABLE NO. 5M - DISPATCHABLE

CALENDAR YEAR	BUYER'S ENERGY AVOIDED COSTS DISPATCHABLE ON-PEAK ($/MWh) [1] FROM ATTACH-MENT A1M	OFF-PEAK ($/MWh) [2] FROM ATTACH-MENT A2M	BUYER'S CAPACITY AVOIDED COST ($/MW) [3] FROM ATTACH-MENT A4	BUYER'S COST AVOIDED (ANNUAL) (M $) [4] SEE NOTE (1) BELOW	BUYER'S PRESENT VALUE DISCOUNT FACTOR [5] [5] FROM TABLE 3M	PRESENT VALUE OF BUYER'S COST AVOIDED (M $) [6] [4]*[5]	"X" TIMES PRESENT VALUE OF BUYER'S COST AVOIDED (ANNUAL) (M $) [7] [6]*"X"	"X" OF BUYER'S COST AVOIDED LEVELIZED (M $) [8] SEE NOTE (2) BELOW	NON - LEVELIZED BALANCE - BUYER'S COST AVOIDED (ANNUAL) (M $) [9] [4] * (1 -"X")	REFERENCE PAYMENT SCHEDULE (M $) [10] [8]+[9]	BUYER'S PAYMENTS (ANNUAL) (M $) [11] [11] FROM TABLE 4M-DISPATCH.	PRESENT VALUE OF BUYER'S PAYMENTS (M $) [12] [11]*[5]	PAYMENTS IN EXCESS OF REFERENCE (M $) [13] [11]-[10]	CUMULATIVE PAYMENTS IN EXCESS OF REFERENCE (M $) [14] CUMULATIVE OF [13]
1987	0.0	0.0	0	0.0	1.0000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988	0.0	0.0	0	0.0	0.8985	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1989	0.0	0.0	0	0.0	0.8073	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1990	0.0	0.0	0	0.0	0.7253	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	43.5	40.9	36448	14388.9	0.6517	9376.6	1875.3	6686.8	11511.1	18197.9	13523.2	8812.5	-4674.7	-4674.7
1992	47.6	44.3	19354	13353.9	0.5855	7818.6	1563.7	6686.8	10683.1	17369.9	14395.5	8428.5	-2974.4	-7649.1
1993	53.2	48.9	30441	16585.2	0.5261	8724.7	1744.9	6686.8	13268.1	19955.0	16210.7	8527.7	-3744.3	-11393.4
1994	60.4	55.7	63737	22990.3	0.4726	10866.2	2173.2	6686.8	18392.3	25079.1	18413.3	8702.9	-6665.8	-18059.2
1995	68.1	62.2	97751	29488.1	0.4247	12522.4	2504.5	6686.8	23590.5	30277.3	20866.7	8861.2	-9410.6	-27469.7
1996	77.0	68.6	112697	33670.1	0.3815	12846.6	2569.3	6686.8	26936.1	33622.9	23057.0	8797.3	-10565.9	-38035.6
1997	80.7	67.5	110691	35782.9	0.3428	12266.6	2453.3	6686.8	28626.3	35313.1	26102.0	8947.9	-9211.1	-47246.7
1998	86.9	71.7	106413	38013.3	0.3080	11708.2	2341.6	6686.8	30410.6	37097.5	29429.0	9064.2	-7668.4	-54915.1
1999	88.5	68.3	102341	38545.0	0.2767	10666.6	2133.3	6686.8	30836.0	37522.8	32545.7	9006.4	-4977.2	-59892.3
2000	94.8	73.8	98404	40044.8	0.2486	9956.6	1991.3	6686.8	32035.8	38722.7	35436.6	8810.8	-3286.0	-63178.3
2001	100.5	80.2	94652	41800.5	0.2234	9337.9	1867.6	6686.8	33440.4	40127.2	38291.8	8554.1	-1835.4	-65013.7
2002	105.4	86.9	90961	44342.6	0.2007	8900.1	1780.0	6686.8	35474.0	42160.9	42283.9	8486.9	123.1	-64890.6
2003	110.0	93.6	87328	47050.2	0.1803	8484.7	1696.9	6686.8	37640.2	44327.0	46533.9	8391.6	2206.9	-62683.8
2004	116.8	101.3	82751	49210.4	0.1620	7973.3	1594.7	6686.8	39368.3	46055.1	50300.5	8149.9	4245.4	-58438.4
2005	122.7	110.6	80243	53532.7	0.1456	7793.0	1558.6	6686.8	42826.2	49513.0	56596.4	8239.0	7083.4	-51355.0
2006	130.8	126.2	76836	60605.6	0.1308	7926.9	1585.4	6686.8	48484.5	55171.3	65491.2	8565.9	10319.9	-41035.1
2007	138.6	134.5	73663	66731.9	0.1175	7842.1	1568.4	6686.8	53385.5	60072.3	74955.8	8808.5	14883.5	-26151.6
2008	146.9	144.9	70920	75334.6	0.1056	7954.2	1590.8	6686.8	60267.7	66954.5	86878.5	9173.1	19924.0	-6227.6
2009	156.5	157.5	68694	85191.2	0.0949	8081.7	1616.3	6686.8	68152.9	74839.7	100446.9	9528.9	25607.1	19379.5
2010	168.3	172.0	66916	97758.3	0.0852	8332.3	1666.5	6686.8	78206.6	84893.4	117184.0	9988.0	32290.6	51670.1
2011	0.0	0.0	0	0.0	0.0766	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.0	0.0	0	0.0	0.0688	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	0.0	0.0	0	0.0	0.0618	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0	0.0	0.0555	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0	0.0	0.0499	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

[15] PV OF BUYER'S DISPATCHABLE COSTS AVOIDED = SUM OF COL [6] ------- = 189379.2
[16] PV OF BUYER'S DISPATCHABLE PAYMENTS = SUM OF COL [12] ----------- = 175845.4
Difference = 13533.8
[17] DISPATCHABLE PRICE RATIO (MEDIAN) {MUST BE <1} = [16]/[15] ------ = 0.929
NOTE: IF [17] = < .25 THEN [17] MUST BE SET EQUAL TO .25

Where "X" equals .35 if Primary Fuel is Solid Fuel, or equals .20 if Primary Fuel is Oil & Gas.

[18] SCENARIO PRICE FACTOR (MEDIAN, DISPATCHABLE) = (1-[17])/.75 ----- = 0.095

NOTE: (1) [4] = (([1] * [3] FROM TABLE 4M - DISP.) + ([2] * [4] FROM TABLE 4M - DISP.) + ([3] * [15] FROM TABLE 4M - DISP.))/1000
NOTE: (2) [8] = SUM OF COL [7] FOR CONTRACT YEARS OF OPERATION / SUM OF COL [5] FOR CONTRACT YEARS OF OPERATION

Table 2-4b

JCP&L PROJECT PROPOSAL
PROJECT: __________Peaking

SELLER'S PROJECTIONS IN BUYER'S SCENARIO

SCORING TABLE NO. 4M - DISPATCHABLE

CALENDAR YEAR	VARIABLE ELECTRICITY PRICE PAID BY BUYER DISPATCHABLE ON-PEAK ($/MWh) [1]	OFF-PEAK ($/MWh) [2]	ESTIMATED ANNUAL ELECTRICITY SOLD TO BUYER DISPATCHABLE ON-PEAK (MWh) [3] SEE ATTACH-MENT A1M	OFF-PEAK (MWh) [4] SEE ATTACH-MENT A2M	ANNUAL ELECTRICITY PRODUCTION DISPATCHABLE (MWh) [5] [3]+[4]	SELLER'S DISPATCHABLE ANNUAL ELECTRICAL OPERATING REVENUES: BUYER'S VARIABLE PAYMENTS TO SELLER ON-PEAK (M $) [6] [1]*[3]/1000	OFF-PEAK (M $) [7] [2]*[4]/1000	START-UPS (#) [8] SEE ATTACH-MENT A3	COST PER START-UP (M $) [9]	BUYER'S FIXED PAYMENTS (M $) [10]	ELECTRIC OPERATING REVENUE (M $) [11] [6]+[7]+[8]*[9]+[10]
1987	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
1988	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
1989	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
1990	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
1991	36.2	36.2	209151	40315	249466	7565.0	1458.2	260	0.000	4500.0	13523.2
1992	40.8	40.8	204975	37663	242639	8359.5	1536.0	260	0.000	4500.0	14395.5
1993	45.4	45.4	214946	43022	257968	9757.7	1953.0	260	0.000	4500.0	16210.7
1994	49.9	49.9	229926	48874	278800	11474.2	2439.0	258	0.000	4500.0	18413.3
1995	55.6	55.6	236002	58547	294548	13113.6	3253.2	246	0.000	4500.0	20866.7
1996	62.4	62.4	237905	59578	297483	14840.5	3716.5	244	0.000	4500.0	23057.0
1997	68.0	68.0	249148	68335	317483	16952.4	4649.6	229	0.000	4500.0	26102.0
1998	76.0	76.0	254182	73791	327973	19320.2	5608.8	221	0.000	4500.0	29429.0
1999	82.8	82.8	256529	82089	338617	21246.7	6798.9	213	0.000	4500.0	32545.7
2000	92.1	92.1	257117	78968	336085	23667.6	7269.0	215	0.000	4500.0	35436.6
2001	100.0	100.0	257412	80446	337858	25745.8	8046.1	214	0.000	4500.0	38291.8
2002	108.0	108.0	261149	88748	349897	28200.4	9583.5	204	0.000	4500.0	42283.9
2003	116.0	116.0	267501	95005	362506	31017.7	11016.2	195	0.000	4500.0	46533.9
2004	126.1	126.1	268032	95109	363141	33805.1	11995.5	194	0.000	4500.0	50300.5
2005	136.4	136.4	269243	112702	381945	36724.1	15372.3	180	0.000	4500.0	56596.4
2006	149.0	149.0	271723	137673	409396	40480.9	20510.3	159	0.000	4500.0	65491.2
2007	162.7	162.7	274169	158839	433008	44610.8	25845.0	142	0.000	4500.0	74955.8
2008	176.3	176.3	277043	190109	467152	48854.3	33524.2	116	0.000	4500.0	86878.5
2009	192.3	192.3	280836	218166	499002	53998.5	41948.4	92	0.000	4500.0	100446.9
2010	210.4	210.4	281610	253922	535532	59255.0	53429.1	65	0.000	4500.0	117184.0
2011	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
2012	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
2013	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
2014	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0
2015	0.0	0.0	0	0	0	0.0	0.0	0	0.000	0.0	0.0

		ALL HOURS	DISPATCHABLE ON-PEAK		DISPATCHABLE OFF-PEAK
[12] SELLER'S PROJECTED AVERAGE AVAILABILITY (%)	[12]	90.0%			
SELLERS PROPOSED DISPATCHABLE MW(ISO) ON-PEAK [13] AND OFF-PEAK [14]			[13] 100.0	[14]	100.0
SELLERS PROPOSED DISPATCHABLE MW (SUMMER CONDITIONS) ON-PEAK [15] AND OFF-PEAK [16]			[15] 100.0	[16]	100.0

Table 2-5 summarizes a numerical example of this kind. It is based on simple modifications of Table 2-1. The avoided plant and the bid prices are left unchanged, but the duration hours for all alternatives are reduced. The results here show that the peaking bid is preferred by both the differential and ratio score. Its differential score is better than in the previous example because, in this case, it runs more hours relative to the avoided plant. The differential scores of the other alternatives are worse. Indeed, the baseload bid would raise rates in this case, even though on a variable cost basis it would be economic to operate for 6000 hours/year. The avoided variable costs in this case are not sufficient, however, to offset the large fixed costs.

Table 2-5
Alternative Example

Alternative	Duration	Differential Score	Ratio Score
Avoided	300		
Peak	500	21	0.845
Intermediate	1900	4	0.987
Baseload	6000	-1	1.002

We conclude that differential scoring is both unbiased and the correct way to evaluate the price component of dispatchable bids. Put simply, the utility is seeking to purchase kilowatts of capacity at the lowest cost, measuring bid value in terms of $/kW savings is the natural measure. If the power system appears to "need" baseload or peaking capacity, the differential method will correctly value alternatives in either case. The ratio score cannot do the same.

3. FRONT-LOADING SECURITY: MEASUREMENT, POLICY AND COSTS

This section addresses the issues of front-loading and the associated security requirements which sometimes appear in power purchase contracts. Two of the contracts reviewed in Section 1.2 have explicit security requirements that are related to front-loading. The Dartmouth Power contract lists both specific dollar amounts (over a ten year period) and the necessary security instrument (an irrevocable letter of credit). The Cogen Technologies contract lists a schedule of security requirements (depending on actual project start date), but allows for some potential substitutes for a letter of credit.

There is some ambiguity concerning where these security requirements originate, and policy with respect to defining them is not uniform. The definitional issues are taken up in Section 3.1. Separate from the definitions are policy questions concerning whether and under what circumstances these requirements ought to be imposed. The range of options and practices is reviewed in Section 3.2. Finally, there are different ways of assessing security costs which are surveyed in Section 3.3. These are relevant to other forms of security unrelated to front-loading.

3.1. Defining and Measuring Security Requirements

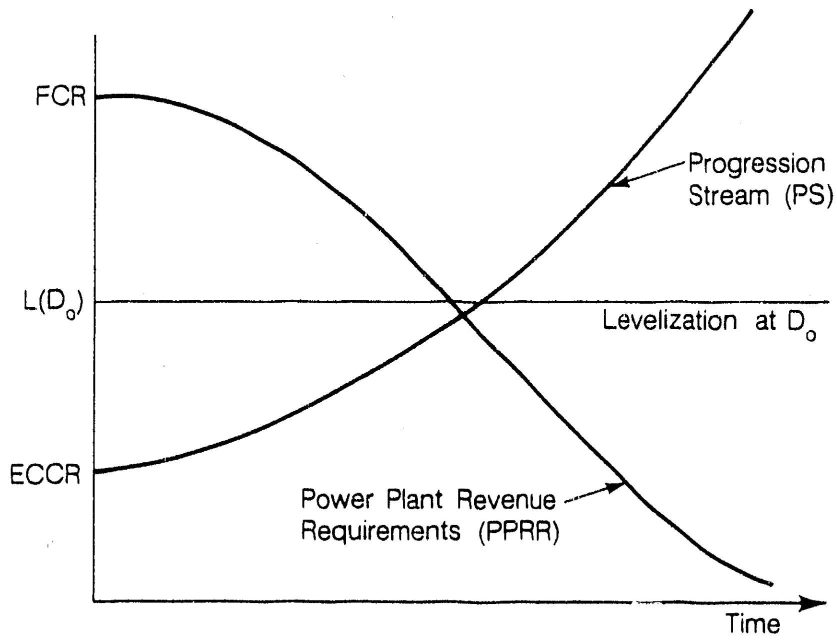
Front-loading is a comparative term. It is used to describe the situation in which the price projection for a private power contract exceeds some estimate of future avoided cost in the initial years of the contract and is lower than this estimate in the long run. The price is called front-loaded because it is greater than the estimate of value at the start of the contract. Our model of pricing scoring for curtailable power in Section 2 suppressed this issue because avoided cost and bid prices were analyzed in levelized terms. Levelization is a mathematical convenience which compresses the time dimension into a single numeraire. It is precisely the time dimension, however, that is the essence of the front-loading question.

The problem of evaluating front-loaded bids has been analyzed previously, given an avoided cost trajectory. It is useful to ask where these trajectories come from in the first place, however, because the answer to this question will shed some light on the origin and magnitude of the problem, as well as on policy questions.

Avoided cost estimates are typically the sum of forecasts for avoided energy and capacity costs. The usual scenarios show both of these components escalating at some rate which is equal to or greater than the general level of inflation. The reasons for the assumed escalation differ substantially between the capacity and energy components. The energy cost escalation is founded on forecasts of competitive market prices for fuels, based usually on the econometric models of independent economic forecasting firms. The capacity cost escalation is the result of an allocation convention known variously as the economic carrying charge rate, or the rental rate on capital. This procedure, while reasonable for many purposes, is still a fundamentally theoretical representation of capital recovery for capacity costs that, in fact, is diametrically opposite to standard regulatory treatment of utility capital investment. Figure 3-1 illustrates this difference. Because the rental rate stream of costs and the standard rate base treatment are so different, there is often confusion about which treatment is appropriate in which situation. The progression stream in Figure 3-1 is the result of using the rental rate approach.

To illuminate this question, it is useful to derive the rental rate approach from first principles so that the assumptions underlying its use can be made clearer. It also turns out that this subject is not particularly well treated in the literature. The most explicit discussion is a report

Figure 3-1



Economic carrying charge rate, levelization, and fixed charge rate. (FCR - fixed-charge rate, $L(D_0)$ = levelized rate at discount rate of D_0 and ECCR = economic carrying charge rate.)

prepared by NERA for an EPRI rate design study more than ten years ago (NERA, 1977). Even that discussion is very qualitative, and does not motivate the formulas used to compute the rental rate in practical situations.

Rent has two components, the interest charge and depreciation, both of which depend on knowing the value of the capital as a function of time, c(t). The interest charge is just the interest rate times the value of the capital at the start of the year, while depreciation is the change in value during the year. We can write this as

$$Rent = r \cdot c(t) + [c(t) - c(t+1)], \tag{3-1}$$

where r is the interest rate and presently serves as both nominal and real interest because inflation is ignored until the next subsection. More details on the variables are given in Table 3-1.

Clearly the crucial task in computing rent is to find the value of capital as a function of time, $c(t)$. There are two ways to approach this problem and they both give valuable insights into the meaning of the rent on capital, so we will discuss both, though only show how to compute $c(t)$ using the simpler approach.

Table 3-1: Variable Definitions	
Rent	Rent is paid at the *end* of each year.
C	Value of new plant at the start of year 1.
$c(t)$	Value of a plant (that was new at time 0) at the beginning of year t.
$c(a)$	Value of a plant that is a years old.
L	Life of plant in years.
r	Real annual interest rate.
i	Annual inflation.
nr	Nominal annual interest rate. $1 + nr = (1 + r)\cdot(1 + i)$.
α	Annual price decrease due to technical progress.
z	Annual price increase due to inflation and technical progress. $(1 + z) = (1 + i)/(1+\alpha)$.

The first and more simple approach is to compare the cost of owning new capital with the cost of owning old capital. This is a little tricky because the old capital wears out sooner and must be replaced. Let us consider the comparison in detail. We need two scenarios of equal value that involve new and old plants. Consider buying a new plant, and holding it for its life of L years until it retires. As an alternative of equivalent value consider buying a used plant. In order to make this alternative of equal value, the used plant will have to be replaced when it retires; we will do this by buying a new plant. Now if the used plant were age a when purchased, the new plant will be age a at the end of L years from the start of our scenario; consequently it should have a value at that time exactly equal to the value of the original used plant at the time it was purchased. Consequently at the end of the scenario we sell the once-new plant for exactly what we paid for the original used plant. This gives us our name for this approach to capital valuation, we will call it the "resale" approach.

To keep this example simple, we assume that the plant does not wear out gradually, but maintains its full usefulness until the end of year L, at which point it simply dies. Since both scenarios provide a fully functional plant for L years, they are of equal value, and it is this fact that we express in our first equation.

Price of New Plant = Price of Used Plant

+ Discounted Price of New Replacement Plant

− Discounted Value of Used Replacement Plant

We need to discount the second and third terms on the right hand side appropriately. Formally we have

$$C = c(a) + \frac{C}{(1 + r)^{L-a}} - \frac{c(a)}{(1 + r)^{L}} \tag{3-2}$$

Rearranging terms we have

$$C \cdot \left[1 - (1 + r)^{-(L-a)}\right] = c(a) \cdot \left[1 - (1 + r)^{-L}\right]. \tag{3-3}$$

And now solving for $c(a)$ we have our desired result.

$$c(a) = \frac{C \cdot \left[1 - (1 + r)^{a-L}\right]}{1 - (1 + r)^{-L}}. \tag{3-4}$$

This equation gives us the value of a plant of age a, so if a plant is new at time zero, it will also give us the value of that plant at all future times. Thus

$$c(t) = c(a).$$

As we mentioned earlier, there is a second approach to computing the value of capital, which we will call the present-value approach. This approach notes that the value of capital equals the present value of the net income stream it will generate. Since that income stream decreases in length as the capital ages, the value of the capital declines with time. It is interesting to note that we have derived the formula for economic depreciation on our way to developing the formula for rent.

Derivation of $c(t)$ by the present-value approach is given in Appendix B. All that needs to be mentioned here is that the two methods give the same result. This shows that the present value of a plant is the same value that the market would place on it if there were a market for used plants. We can now move on to the computation of rent from plant value.

Equation (3-1) gives us the rent in terms of $c(t)$. We now have a formula for $c(t)$, so substitution followed by a little algebraic simplification produces our desired formula for rent. This process gives us

$$\frac{Rent}{C} = r \cdot \left[1 - (1 + r)^{-L}\right]^{-1} \tag{3-5}$$

Notice that rent is constant (there is no dependence on t in (3-5)); the decrease in interest payments is exactly offset by the increase in the rate of depreciation. This is to be expected since the plant is equally productive at all points in its life cycle. Still this is an important point because it is often assumed that the cost of a plant is incurred when it is purchased or during the time the loan is being paid off. These assumptions imply that the cost of a plant is virtually nil during the second half of its life. This is not the case; rent depends on the usefulness of the capital and not on when it is purchased. Rent is the proper measure of the cost of capital, because it correctly attributes the cost to those who benefit from it.

So far, in order to facilitate exposition, we have developed the basic theory of rent under very restrictive assumptions. Of the many real-world conditions that can be taken into account, the three most prominent are inflation, technical progress, and increasing maintenance costs over the life of the plant. Appendix B derives the rent formula taking into account the first two conditions. Here we will only present the result that accounts for inflation.

To present the result we must introduce inflation, i, and the nominal rate of interest, nr. The new rent equation is:

$$\frac{Rent}{C} = (nr - i) \cdot \left[1 - \left[\frac{1+i}{1+nr}\right]^{L}\right]^{-1} \cdot (1 + i)^{t-1} \tag{3-6}$$

This is the standard handbook formula for rent. Note that rent now depends on time, but that the time term evaluates to one at time 1, so the first two terms give the first year's rent. Now we notice something a bit odd about this formula, which is that the first year's rent appears to depend on the rate of inflation. In fact it does, but only because we have kept with tradition and specified that rent is paid at the end of the year; after a year's worth of inflation has occurred. If we re-write this equation for rent paid at the beginning of the year, R_0, we find it simpler and easier to interpret.

$$\frac{R_0}{C} = \frac{r}{1 + r} \cdot \left[1 - (1 + r)^{-L}\right]^{-1} \cdot (1 + z)^{t-1} \tag{3-7}$$

We see that initial rent depends separately on neither nominal interest nor the rate of inflation, but only on the real rate of interest, r. The nominal rent however increases over time due to inflation, just as one would expect.

Appendix B analyses technical progress as well as inflation, and finds that the greater the rate of technical progress, the greater is the initial level of rent. This is because progress causes depreciation. If a new machine costs P today, but in one year an identical new machine will cost $P/2$, then the value of todays machine will fall by at least 1/2 over the course of a year and this must be covered by rent. Appendix B shows that the rate of technical progress enters the rent formula in exactly the same way as the real interest rate.

Although we do not include any analysis of maintenance costs it is worth stating the basic result regarding their effects on rent. Maintenance costs must be deducted from the rent we calculate in order to find the true rent. Thus, if they increase as the plant ages, rent decreases.

3.2. Policy Choices Associated with Front-Loading

There are two kinds of policy choices affecting the treatment of front-loading. The first involves the method of defining avoided cost. The second involves the degree to which utilities and regulators are comfortable with payment streams having time patterns other than those which escalate. In practice these two issues cannot easily be separated. One definition of avoided cost will imply a different degree of front-loading than another depending on how the avoided cost standard is characterized. In this section we will survey the kinds of choices that are available along each dimension and the policies that have been adopted by various utilities and jurisdictions.

3.2.1. Avoided Cost Definition

In particular situations, the relative shares of energy and capacity costs in the total avoided cost forecast will vary. Jurisdictions which base avoided capacity costs on the capital costs of baseload power plants will have a large share for this term in the total avoided cost estimate. The opposite case involves the use of peaking plant costs for this purpose. California, for example, has typically adopted the peaking plant definition of avoided capacity costs and used this for its standard offer contracts. In the 1980s the California Public Utilities Commission (CPUC) allowed QFs signing long term firm capacity contracts to receive levelized capacity payments based on this standard. As it shifted orientation toward competitive bidding for these contracts, the CPUC also turned toward the rental rate approach for contract pricing. In marginal cost studies for rate design, the CPUC has typically relied on the rental rate method.

Other states have used baseload power plants as the proxy for avoided cost and commonly treated their fixed costs as the relevant capacity costs. Texas, for example uses this approach, but invokes the rental rate method for developing a stream of yearly avoided capacity costs. In Oklahoma, the avoided unit, on which capacity payments were based, was also a baseload power plant. The AES Shady Point contract (see Section 1.2.10) is designed to mimic the stream of regulated rate base fixed costs closely, even though the resulting pattern would be front-loaded by definitions based on the rental rate theory.

Another issue involves the case where the utility is purchasing a large amount of power relative to its total capacity (say more than 10%). In this case the avoided cost will typically be based on a mix of avoided facilities. Should the average capacity cost of this mix be used as the benchmark avoided cost? Perhaps it would make more sense to use a different avoided capacity cost for different kinds of plants. In this situation, Virginia Power uses the mix of avoided plants to define a total present-value of avoided fixed costs. The rental rate theory is then used to construct a smoothly escalating stream of avoided annual capacity costs with the same present-value.

As competitive bidding occupies a larger role in electric utility capacity expansion, the notion of avoided cost becomes more tenuous. The avoided cost may be more difficult to construe as a utility built alternative, than as a power purchase contract resulting from the competitive bidding process. If competitive bidding requires some kind of levelized capacity pricing, then in the long run this formula will become standard and the whole notion of front-loading may disappear as an issue. This evolutionary outcome is still premature, and so the issue remains proximate.

Finally, it is possible that front-loading could disappear as an issue if capital market constraints eased. One of the driving forces behind the front-loading issue is the relatively burdensome loan terms facing the private power market. There is already some indication that financial terms, such as longer loan maturities, are getting more favorable for independent power projects (Marier, 1990). Such changes are still relatively small compared to the changes that would be necessary to eliminate the need for front-loaded pricing.

3.2.2. Policy Issues

Policy choices on front-loading security reflect the degree to which utilities and regulatory commissions perceive risks in these pricing arrangements. Risk perception, in turn, implies policy choices about encouraging private power production. Attitudes can change over time. In California, for example, the regulatory climate was quite favorable to private power development in the early 1980s. The CPUC viewed its role as supportive of the emerging QF industry (Hulett, 1989). Providing levelized capacity payments in standard offer contracts was part of that policy. By the end of the decade, however, the size of private power development was so substantial that public policy discussions had turned to issues of excess capacity (CEC/CPUC, 1988). In its decisions on competitive bidding for private power contracts, the CPUC disallowed any front-loaded prices by requiring that bids emulate the rental rate stream of capacity prices (CPUC, 1986).

Virginia Power (VP) represents a diametrically different policy approach. In its Capacity RFPs, VP allows bidders to levelize capacity payments without penalty in the evaluation phase. Neither does it require security in the contracts associated with front-loading. The utility does impose a security requirement of $36/kW, but this applies to all projects without discrimination by fuel type or other specific characteristics. There is a restriction on the levelization of capacity payments which limits the present-value in the first fifteen years of contract life to 90% of the present-value of lifecycle capacity payments. This allows bidders to increase prices to a limited extent in the last ten years of the contract.

3.3. Assessing the Cost of Front-Loading

Fundamentally, front-loading, assuming it is a real problem, is best conceived of as a loan from the purchasing utility and its customers to the developers of a private power project. The loan is necessary because of capital market constraints on developers. The risk that it imposes on ratepayers is essentially the same risk to any lender, namely that the loan will not be repaid. In this context, repayment means that the power project will operate as promised at the price promised for the duration of the contract. If this occurs, then the utility and its customers will have received enough value in return for the loan to more than compensate for its risk. These arguments have been formalized elsewhere in the context of multi-attribute bid evaluation (Stoft and Kahn, 1990).

By the previous argument that front-loading is a loan, it is reasonable to assess its costs by methods used in the loan markets. There are essentially two approaches that can be taken to pricing the risks of front-loading. One is a penalty in the bid evaluation stage. The other is a security arrangement for the amount of utility ratepayer exposure. Practices in the competitive bidding market have used both approaches, typically in a fairly ad hoc fashion. In this section we investigate both approaches, define their domains of applicability and assess their costs.

We begin with security arrangements. These have been reviewed recently by vendors of an insurance product that appears to offer significant new alternatives (Ikemoto and Carlow, 1989). The ideal arrangement from the utility's point of view is either a full letter of credit or an escrow account to secure the total front-loading exposure. These alternatives are very costly. If the letter of credit is a responsibility of the project-financed entity selling the power, it is equivalent to debt. Since independent power projects are typically financed with the maximum possible debt, the letter of credit will limit leverage to cover capital costs (Kahn, Chapter 6, 1988). Alternatively, the letter of credit must come from equity whose cost is even higher than debt.

Project-funded escrow accounts have been used in some cases to provide a fund that will cover the utility's exposure. Ikemoto and Carlow claim that typical arrangements of this kind involve 5-7% of project revenue collected over a 15-20 year period. Further they point out that potential tax liabilities on this revenue will accrue to the project.

The insurance option is a newer approach, which will not have universal applicability, but offers significant economies. The insurer can diversify risk by holding a portfolio of commitments. It must obtain the technical expertise to evaluate the capability of projects to meet their performance requirements. At least one firm supplies these services in the steam boiler segment of the power market. Its product is available to insure front-loading exposure for periods of 3 to 5 years at an annual cost of 3-6% of the insurance obligation. This is considerably cheaper than either the letter of credit or escrow account alternatives.

Security requirements for front-loading exposure can also be traded off against the cost of power. If a front-loaded project is otherwise sufficiently less costly than an equivalent non-front-loaded project, then the utility should be indifferent. The lower cost compensates for the risk. These assessments are properly made at the bid evaluation stage. Stoft and Kahn show that any bid evaluation system can be translated into one where the front-loading exposure is expressible as a loan that is charged a specific interest rate. The appropriate interest rate should reflect the risk cost of default, and therefore should be higher than the standard discount rate used by the utility for present value discounting of the power contracts costs. This approach is called the Implicit Loan Method (ILM) of bid evaluation.

The key parameter in the ILM is the risk premium. One measure of the risk cost is the interest rate on junk bonds, which are loans with a significant probability of default. Typically such loans have interest rates in the 13-20% range. Those bonds at the high end of this range would be quite likely to default; their risk is probably greater than the risks associated with most front-loaded power contracts. A representative risk-adjusted interest rate in this range would be 17%. Compared to standard utility discount rate of 11-12%, the risk cost of front-loading would be approximately 5-6%. This is probably an upper bound estimate.

Comparing the costs of project security insurance with the bid evaluation penalties of the implicit loan method is not completely straight-forward. One way to compare the two approaches in a specific situation is to calculate the conventional front-loading exposure, and the corresponding insurance cost. Add the insurance costs to the bid price and compute a price score; call it P1. Next use the implicit loan method to find the risk premium which will also produce P1. If the risk premium required to produce equal scores is very small, then insurance is cheap. If a very large risk premium is required to produce equal scores, then the insurance is expensive. To implement this comparison first we need to update the ILM to our new results involving dispatchability.

3.3.1. Updating the Implicit Loan Method for Dispatchability

In light of our results from Section 2 on the inapplicability of the ratio score method, it is worthwhile to reconsider the way the Implicit Loan Method (ILM) should be integrated with a scoring system.

The defining equations for the ILM are

$$C(t) = b \cdot A(t) + L(t) \tag{3-8}$$

$$PV_R[\, L(t) \,] = 0 \tag{3-9}$$

Equation (3-8) says that the cost of a bid can be divided into a non-front-loaded component that is proportional to avoided cost and a loan component. The second equation says that the utility is not trying to turn a profit on the loan, i.e., its present value is zero. The loan, $L(t)$, includes both payments and repayment, and its present value is evaluated at an interest rate, R, that includes both the utilities normal cost of funds plus a risk premium that just compensates it for the risk of the loan. From these two equations we derived the formula for b:

$$b = \frac{PV_R[\, C(t) \,]}{PV_R[\, A(t) \,]}. \tag{3-10}$$

From the equation (3-9) we know that the implicit loan component ($L(t)$), of the cost can be ignored, and $C(t)$, the cost stream of a bid, is equivalent to $b \cdot A(t)$. This makes it easy to compare bids with differing time profiles of their electricity costs, for each C(t) is summarized by the single number b. The question now is how best to make use of the index b.

In our last work we analyzed bid scoring systems that award price points based on the ratio of cost to avoided cost, and on some measure of front-loading. In order to compare these scoring systems with a system based on ILM, we discarded their arbitrary measure of front-loading and replaced their ratio, $PV_r[(C)]/PV_r[(A)]$ with our ratio: $PV_r[(b \cdot A)]/PV_r[(A)]$, which, of course, conveniently reduces to b. Both of these are a ratio-scoring system, as discussed in Section 2. At that time we did not realize that scoring systems based on the ratio of cost to avoided cost are faulty when applied to auctions with dispatchable bids. Consequently, while our analysis was useful for its limited purpose of analyzing the treatment of front-loading in bid evaluation schemes, it was misleading because it gave the impression that the "price factor", b, which is inherently a ratio score, could be used directly.

The price factor, b, should still play its crucial role, but we must find a way to build a differential score from it. Fortunately this is easy. As we have shown in Section 2 of this paper, dispatchable bids must be scored on the basis of the difference between their per-kilowatt avoided cost and their per-kilowatt cost. The first step then is to scale $A(t)$ to a per-kilowatt basis, by dividing by the capacity for which $A(t)$ was calculated. We call the scale version $a(t)$. Now to form a differential score, we must calculate

$$\text{differential score} = \text{PV(avoided cost)} - \text{PV(cost)}$$

As described above, the cost stream of a bid, after taking into account the risk of any front-loading, is equivalent to $b \cdot A(t)$, or on a per-kilowatt basis, to $b \cdot a(t)$. Now, since the loan has been removed from the cost stream, and its risk accounted for by R in the process, we do not want R, but rather the utility's normal cost of funds, r, when we take the present value of the cost. This brings us to a functional definition of the differential score.

$$\text{differential score} = PV_r[\,a(t)\,] - PV_r[\,b \cdot a(t)\,]$$

Which simplifies nicely to

$$\text{differential score} = (1-b) \cdot PV_r[\,a(t)\,]$$

3.3.2. A Simple Example

To assess the cost and value of front-loading performance insurance, it is helpful to work with a concrete example. We use recent data from Virginia Power (VP) 1988 avoided cost projections, and cost data associated with their Clover generating station. Table 3-2 shows annual values of VP avoided cost for capacity and energy in the columns labelled "Ceiling." The capacity values are expressed in dollars per kW, and the energy values in cents per kWh. The capacity values represent a rental rate stream based on a mix of avoided plants (Carney, 1988). The energy payment stream represents the output of production simulation models (Green, 1988). The data in the columns labelled "PMT" represent levelized capacity costs per kW and escalating energy costs of the Clover generating station that VP is constructing in association with Old Dominion Electric Co-operative. These values are derived from testimony presented by VP to the Virginia State Corporation Commission seeking a certificate of convenience and necessity (CCN) for this project (Ellis, 1989).

For the purposes of this example, we are treating Clover as if it were a bid being evaluated against the avoided cost stream of the company. In fact, the VP testimony in support of the CCN explicitly compared Clover to bids received in the VP 1988 Capacity RFP. The bid stream in Table 3-2 is also roughly similar to the prices in the Vista/Paulsboro contracts (see Section 1.2.9).

The columns in Table 3-2 labelled "Overpayment" represent the standard approach to calculating security requirements. The calculations are all made on a per kW basis, which requires specification of the operating hours for the project. Overpayments are quite sensitive to the number of operating hours because the benefits of the project are all on the energy side. The capacity price exceeds avoided capacity costs for ten years. In this example we assume the project operates for 6600 hours per year. This is approximately 75% capacity factor which is representative of good baseload performance. For each year the difference between avoided cost and project payment is computed in the column labelled "Annual." For example, the first line shows a value of \$51/kW. This is calculated by taking the difference between capacity ceiling and the levelized payment (204-310 = -106) and adding the energy savings ((.0324-.0240) * 6600 = \$55). Total energy savings (in present value terms) are shown in the columns "Ceiling" and "PMT" on the line labelled "@6600 hrs/yr." This example shows \$705/kW difference between value and bid price (2927-2222 = 705). The security requirement is just the cumulative negative balance of these annual net overpayments, with interest charged on the outstanding balance at the utility's discount rate.

The last column, labelled "Insurance," is just 5% of the cumulative exposure or security requirement in each year. This is the performance insurance premium, assuming such a policy is in force. We accumulate these costs and add them to the bid price. This adjusted bid price is then used to compute a price score. The present-value (at the utility discount rate of 10%) of the insurance premiums is \$27/kW. Adding this to a present value bid price of \$5062/kW (= 2222 + 2840) yields an adjusted bid of \$5089/kW. The present value avoided cost is \$5737/kW (2809+2927), so the difference score is \$648/kW.

Table 3-3 repeats the first five columns of Table 3-2. The last two columns are used to implement the Implicit Loan Method. For this example we know what price score we want to reproduce; i.e. \$648/kW. The output of the exercise will be a risk adjusted discount rate, R, which is consistent with such a price score. First we translate the price score into ratio terms; \$648 is 0.113 times the avoided cost of \$5737/kW. This means that the present-value of the bid price divided by the present value of avoided cost should be 0.887, where these present values are computed using the risk adjusted rate, R, which will be greater than the normal discount rate of 10%. The column labelled "Delta b=0.887" is the annual difference between b times avoided cost and the bid price. This is the implicit loan cash flow stream. The values in this column are always smaller than the corresponding values in the annual overpayment column next to it.

The iterative part of the calculation involves searching for a discount rate, R, which will give a zero present value to the implicit loan cash flow stream. Table 3-3 shows that the discount rate which achieves this is approximately 10.5%. The precise value would be slightly lower. We know this because there is still a small negative balance in the cumulative column (alternatively the present value of the implicit loan cash flow stream is slightly negative). To verify that the risk rate of 10.5% is consistent, we discount the avoided cost stream and the bid price stream at

Table 3-2
Simple Example: Security Covered by Insurance

Year	Capacity Price Ceiling	PMT	Energy Price Ceiling	PMT	Overpayment Annual	Cum @10%	Insurance
1990	146		2.25				
1991	159		2.36				
1992	173		2.78				
1993	195		3.08				
1994	204	310	3.24	2.40	-51	-56	-2.78
1995	214	310	3.41	2.52	-37	-102	-5.12
1996	224	310	3.68	2.65	-18	-132	-6.61
1997	235	310	3.92	2.78	0	-145	-7.26
1998	246	310	4.05	2.92	11	-148	-7.39
1999	258	310	4.41	3.06	37	-122	-6.10
2000	270	310	4.61	3.22	52	-77	-3.84
2001	283	310	4.74	3.38	63	-15	-0.75
2002	297	310	5.29	3.55	102	96	
2003	311	310	5.25	3.72	102	217	
2004	326	310	6.04	3.91	157	411	
2005	342	310	0.18	4.10	-227	202	
2006	358	310	2.84	4.31	-49	169	
2007	375	310	8.36	4.53	318	536	
2008	393	310	4.62	4.75	75	671	
2009	412	310	4.17	4.99	48	792	
2010	432	310	8.06	5.24	308	1210	
2011	453	310	8.12	5.50	316	1678	
2012	474	310	8.25	5.78	328	2206	
2013	497	310	8.11	6.06	322	2781	
2014	521	310	7.33	6.37	275	3361	
2015	546	310	10.42	6.69	482	4228	
2016	572	310	10.19	7.02	471	5169	
2017	600	310	11.23	7.37	544	6285	
2018	628	310	11	7.74	534	7500	
2019	659	310	11	8.13	538	8842	
PV	2809	2840	44	34	674		-27
@ 6600 hrs/yr			2927.945	2222.858			
Totals	5737.214	5062.751					
Adjust		5089.776					

Table 3-3
Implicit Loan Method

Year	Capacity Price Ceiling	Capacity Price PMT	Energy Price Ceiling	Energy Price PMT	Overpayment Annual	Overpayment Delta b=0.887	Cum @10.5%
1990	146		2.25				
1991	159		2.36				
1992	173		2.78				
1993	195		3.08				
1994	204	310	3.24	2.40	-51	-98	-108
1995	214	310	3.41	2.52	-37	-87	-216
1996	224	310	3.68	2.65	-18	-70	-316
1997	235	310	3.92	2.78	0	-56	-411
1998	246	310	4.05	2.92	11	-47	-506
1999	258	310	4.41	3.06	37	-25	-587
2000	270	310	4.61	3.22	52	-13	-663
2001	283	310	4.74	3.38	63	-4	-737
2002	297	310	5.29	3.55	102	29	-782
2003	311	310	5.25	3.72	102	28	-834
2004	326	310	6.04	3.91	157	75	-839
2005	342	310	0.18	4.10	-227	-267	-1222
2006	358	310	2.84	4.31	-49	-111	-1473
2007	375	310	8.36	4.53	318	214	-1391
2008	393	310	4.62	4.75	75	-4	-1542
2009	412	310	4.17	4.99	48	-30	-1737
2010	432	310	8.06	5.24	308	199	-1699
2011	453	310	8.12	5.50	316	204	-1652
2012	474	310	8.25	5.78	328	213	-1591
2013	497	310	8.11	6.06	322	205	-1531
2014	521	310	7.33	6.37	275	161	-1514
2015	546	310	10.42	6.69	482	343	-1294
2016	572	310	10.19	7.02	471	331	-1064
2017	600	310	11.23	7.37	544	393	-742
2018	628	310	11	7.74	534	381	-399
2019	659	310	11	8.13	538	382	-19
PV @10%	2809	2840	44	34	674	-1.30645	
PV @R	2676	2732	42	32			
@ 6600 hrs/yr			2927.945	2222.858			

Totals	PV @10%/kW	PV @R/kW
Avoided Cost	5737.214	5464.775
Bid	5089.751	4848.562
Ratio	0.887147	0.887239

this rate. These are labelled "PV @R" at the bottom of the table. At this discount rate, the present value of avoided cost is \$5464/kW (2676 + 2788, where 2788 is the NPV of the ceiling energy cost at 6600 hours per year discounted at 10.5%) and the present value of the bid price is \$4848/kW. Their ratio is 0.887 as required.

This example shows that the risk premium corresponding to the insurance cost is low. The risk premium is 0.5%, which is the difference between R and the normal discount rate of 10%. What this result means about security costs and insurance is discussed below.

3.3.3. Interpretation

The risk premium calculated in the example in section 3.3.2 is small. It is far lower than the risk premia associated with junk bonds and is in the range of bond yield spread among investment grade securities. This means it is like the difference in interest cost between an AA rated bond and a BBB rated bond. There are at least three potential interpretations of this result: (1) the actual risk is low, therefore the cost should be low, (2) the insurance scheme achieves a risk spreading economy, which lowers the cost, and therefore the cost should be low, and (3) the insurance does not provide complete security and therefore the price is low because the product coverage is incomplete.

Although there is something to be said for all three potential interpretations, it is the third which is most likely. This can be seen most simply be considering the negotiation between the private producer who wants to buy insurance and the firm that will sell it. Insurance contracts typically require periodic renewal. If the insurer believes that the behavior of the insured is too risky, the policy can be terminated at renewal time. The threat of termination acts as a restraint on the behavior of the insured. In this way the potential moral hazard problem between the two parties can be controlled.

The implications of potential termination are not captured in the calculation of Table 3-2. That calculation *assumes* the insurance is in effect. Therefore it says in effect that the insurance company has determined that the risk is low because the behavior, as far as they can tell, is good. This, incidentally, helps make the case in part for interpretations (1) and (2) above. The main twist here is that because of its specialized knowledge the insurance company can separate low risk producers from high risk producers. It will only insure the former, and therefore its expected cost is lower than say the bank which would issue a letter of credit. The bank, or other issuer of letters of credit, has no specialized knowledge so it cannot separate low risk from high risk producers. Therefore it must charge higher prices since its risk is greater.

The crucial point, however, is that the insurance company cannot *guarantee* coverage over the entire period for which security is required. Any such guarantee sacrifices the disciplinary effect of potential cancellation. Therefore a bidder cannot simply fold insurance costs into his bid price and assure the utility that security requirements would be met. Such claims cannot be believed, because the utility knows that if the insurance is cancelled, there will be no protection against potential default by the bidder. Cancellation, if invoked, protects the insurance company, but not the interest of the utility. For this reason, then, the insurance product, from the utility perspective is weak. When it may be most needed, it will be unavailable. This is the reason why its cost is low. Insurance remains a useful product to provide front-loading security during contract life. The arguments just given show that it is not useful at the stage of bid evaluation. The Implicit Loan Method is a bid evaluation tool. It is not simple to use primarily because it is difficult to price the front-loading risk premium with great accuracy. It is basically a policy question whether utilities should require front-loading security in contracts if they have already imposed penalties on this feature at the evaluation stage. There does not appear to be any consensus on this issue currently.

3.4. Conclusion

Front-loading remains a problematic feature of competitive bidding. Its fundamental cause is imperfections in the capital markets. As private power becomes more familiar to these markets, front-loading may eventually disappear. For now, however, attitudes differ widely across utilities and regulatory commissions about how it should be treated. Although performance insurance can reduce the cost of front-loading security for some producers, it is not a universal solution to the moral hazard problems that lie at the heart of the security question. This insurance may be useful for other security purposes. At bottom a better understanding of the risks involved in long term power contracts, and ways to measure them will provide the most insight into this issue.

4. MODELLING DISPATCHABILITY ATTRIBUTES

4.0 Overview

Dispatchability is a broad term covering various types of operational flexibility. We examine here the cost implications of operating restrictions identified in our review of contracts. The models used to evaluate the price aspects of competitive bids for electric power are not all capable of detecting these cost implications. We use a detailed chronological production simulation model primarily for this analysis. We find that minimum operating capacity restrictions are the most important of all the effects tested.

For a representative intermediate load gas-fired project, restricting operation to between 80% and 100% of capacity incurs a levelized cost penalty of about 10%. A similar restriction for a representative base load coal-fired project incurs a penalty of about 5%. The penalty is lower for baseload resources compared to intermediate load because it is less important to curtail the output low variable cost resources than units using more expensive fuels. The models typically used to score the price aspect of competitive bids need to be corrected for these effects because they cannot be captured using less detailed operating representations.

4.1 Introduction

The term "dispatchability" has been used broadly in our discussions above to mean the ability of generation output to follow fluctuations in load. The analysis in Sections 1 and 2 shows that this attribute of power projects is becoming increasingly important. Traditional utility planning did not give this issue much explicit attention. Planners maintained a rough balance between baseload, cycling and peaking facilities. These rough categories were distinguished by their relative variable costs. Higher operating costs mean less use and vice versa. Capacity expansion typically meant adding new baseload units and pushing older less efficient plants up the loading order. Until the widespread adoption of production simulations models in the 1970s, there was little in the way of analytical tools with which this attribute could be studied. Even with such models, no standard procedure by which to assess dispatchability has emerged.

In this section we will systematize the discussion of dispatchability which has been largely anecdotal up to now. We begin with a review of conditions that have led to the growing importance of dispatchability. We then introduce terminology to differentiate among aspects of the dispatchability attribute. These will be illustrated by example. As a prelude to quantifying the value of dispatchability in detail, we make some preliminary estimates based on the costs of "must-run" PURPA dispatch rules.

4.1.1 History, Terminology and Examples

The evolution of large-scale markets for private power production has forced attention to focus on the issue of dispatchability. The obligation to purchase output from Qualifying Facilities (QF) under PURPA means essentially that utilities are in a "must-take" situation with respect to these producers. When commitments to QF output are large, operating problems can follow. This situation occurred on a number of power systems in the mid-1980's when many QF facilities began operating at the same time as new large baseload power plants came into service. The resulting situation became known as the "minimum load" problem.

The "minimum load" problem refers to off-peak periods when the demand for power is not sufficient to absorb all the output from resources that for various legal or technical reasons cannot be turned off. Utilities faced with this situation cannot usually sell the excess output to their neighbors, because these utilities face a similar problem. The operating problems created by the supply/demand imbalance has produced a need both for more flexibility in baseload generating units and in the power contracts between utilities and private producers. Other trends, particularly the decline in system load factors also increased the demand for more flexibility in the operation of generating units (Electrical World, 1990). In one way or another, this flexibility is referred to as dispatchability.

One important reason why dispatchability has not been analyzed systematically is that the term covers a wide range of related phenomena. We have had occasion to discuss most of these in Sections 1 and 2. In this section we begin to systematize the analysis. We begin with some definitions. For our purposes, we distinguish three distinct aspects of dispatchability: (1) curtailment, (2) commitment, and (3) chronology. Because terminology in this area is not standardized, we define our use of these terms. The definitions offered here are motivated by the hierarchy of analytical procedures that are used to study the three aspects of dispatchability. We will first offer our definitions by describing the problems each is intended to address. Next we will turn attention explicitly to the analytical procedures that are available to study them.

By the term *curtailment* we mean a situation in which a generator's output is reduced due to low demand, but not shut down. The simplest solution to minimum load problems is the curtailment of baseload or QF resources. More broadly speaking, curtailment represents the simplest correction to the busbar cost technique of comparing generation alternatives. Busbar cost expresses the revenue requirements of power projects under the assumption that they produce for an equal number of hours during the year; i.e. have equal capacity factor (see Stoll, et al., 1989, pp. 497-501). The assumption is usually that all new generation will be baseload in nature, meaning that variable costs were low and capacity factor was high. Our critique of the JCPL ratio scoring method in Section 2 showed that when projects can be curtailed economically, there is no simple comparison of average cost to a benchmark avoided cost per kWh.

The decision to start or stop a unit is referred to as *commitment*. The "on/off" decision is a discrete event which involves indivisible costs in the following sense. Once a unit is started it must operate at some minimum level and for some minimum time period. These minima are hard constraints and therefore represent rigidities in the cost structure; i.e. are indivisible. The basic phenomenon addressed by commitment is the need to accommodate daily load fluctuations with generation that cannot follow them completely. To have capacity available to meet daily peak loads some units must often be kept running at minimum output at night, or over the weekend, even though there may be cheaper alternatives. Thus a committed cycling unit may have to operate partially in the base, off- peak, load segment and partially in the intermediate load, on-peak, segment. This occurs because the unit cannot be easily shut down in the evening and later started up again the next day to meet peak loads. Therefore, the need to commit load following units can exacerbate the minimum load problem, because their operation at minimum output adds to "must take" capacity during the off- peak period.

Chronology refers to any situation that involves real time constraints. Such constraints are important in the region of demand where loads are fluctuating. One of the most important chronological constraints is ramping limits. Individual units can vary their output only at specific rates. These ramp rates differ among units. There are situations in which it is important that the output responses occur quickly. If the power system operator must alter the simple economic loading order to accommodate these limits, there is a ramping constraint. Other chronological constraints include spinning reserve requirements and voltage restrictions.

To illustrate these terms more concretely we show two figures representing operating conditions of the Southern California Edison (SCE) system. Figure 4-1 shows the commitment and loading of oil and gas units on this system during a summer week in 1984 (SCE, 1986). The upper line on this graph, called capacity on line, shows the total power capability of units that are on line regardless of the level at which they are operating. While the magnitude of this line shows some fluctuation during the five weekdays, the major change comes with weekend shutdown events that occur at the end of the period shown. The oil and gas units provide most of the load-following capability for the SCE system. The units that are committed ramp up during the day and down at night. But the existence of ramping constraints is shown more clearly in Figure 4-2.

This figure shows schematically the operation of a large storage hydro facility to meet SCE's daily load cycle. This resource is being dispatched during the rapid load change periods in the late morning/early afternoon and late evening. During these periods load may be changing as fast as 20 MW/minute. This figure shows a situation that is directly contrary to much of the conventional wisdom concerning the use of storage hydro resources. The usual picture, often incorporated into the algorithms of production simulation models, is one in which storage hydro is used for "peak-shaving" (Billinton and Harrington, 1978; Staschus, Bell and Cashman, 1989). The basic idea behind the conventional interpretation is that peak loads represent the highest cost production period facing the utility. Storage hydro represents the most flexible resource available to the utility operators. Therefore it should be used to meet those loads with the highest cost to serve. What Figure 4-2 shows is that ramping constraints may well mean that flexibility has more value in this mode than the more static costs of meeting the maximum loads.

As system load factors decline, this situation can be expected to affect more utilities. Further anecdotal evidence to this effect is the ramp rate limits built into SCE's recent power sales agreement with the Sacramento Municipal Utility District (SMUD). This agreement for the sale of up to 300 MW of capacity and energy specifies that load changes cannot exceed 1.5 MW/minute under normal conditions. Even under emergency conditions the limit is 3 MW/minute (SCE/SMUD, 1988).

Additional examples have been indicated in the contract conditions reviewed in Section 1. The Doswell contract, for example, offers the utility commitment without much curtailment. The utility has the right to turn the unit on and to shut it down. Once it is on, however, the contract specifies that it must be operated between 80% and 100% of capacity. In other words the curtailment range is very limited. The TECO Power Services/Seminole contract illustrated a power output profile analogous to Figure 4-2. The combined cycle unit operation shown in Table 3 was basically a ramping pattern. Output increased to daily maxima at 9 AM and then again at 9 PM. Unlike the schematic pattern in Figure 4-2, the unit did not shut down between these time periods, presumably because of limits on the number of start-ups that the equipment can tolerate.

Because dispatchability has the three components we have identified, it is not possible to study all its aspects in one single unified modelling framework. This is essentially a constraint due to the current generation of simulation software. To develop a comprehensive approach to valuing dispatchability attributes, we must identify the limits and capabilities of analytical models that can be used for this purpose.

Figure 4-1
Committed Capacity vs Loaded Capacity

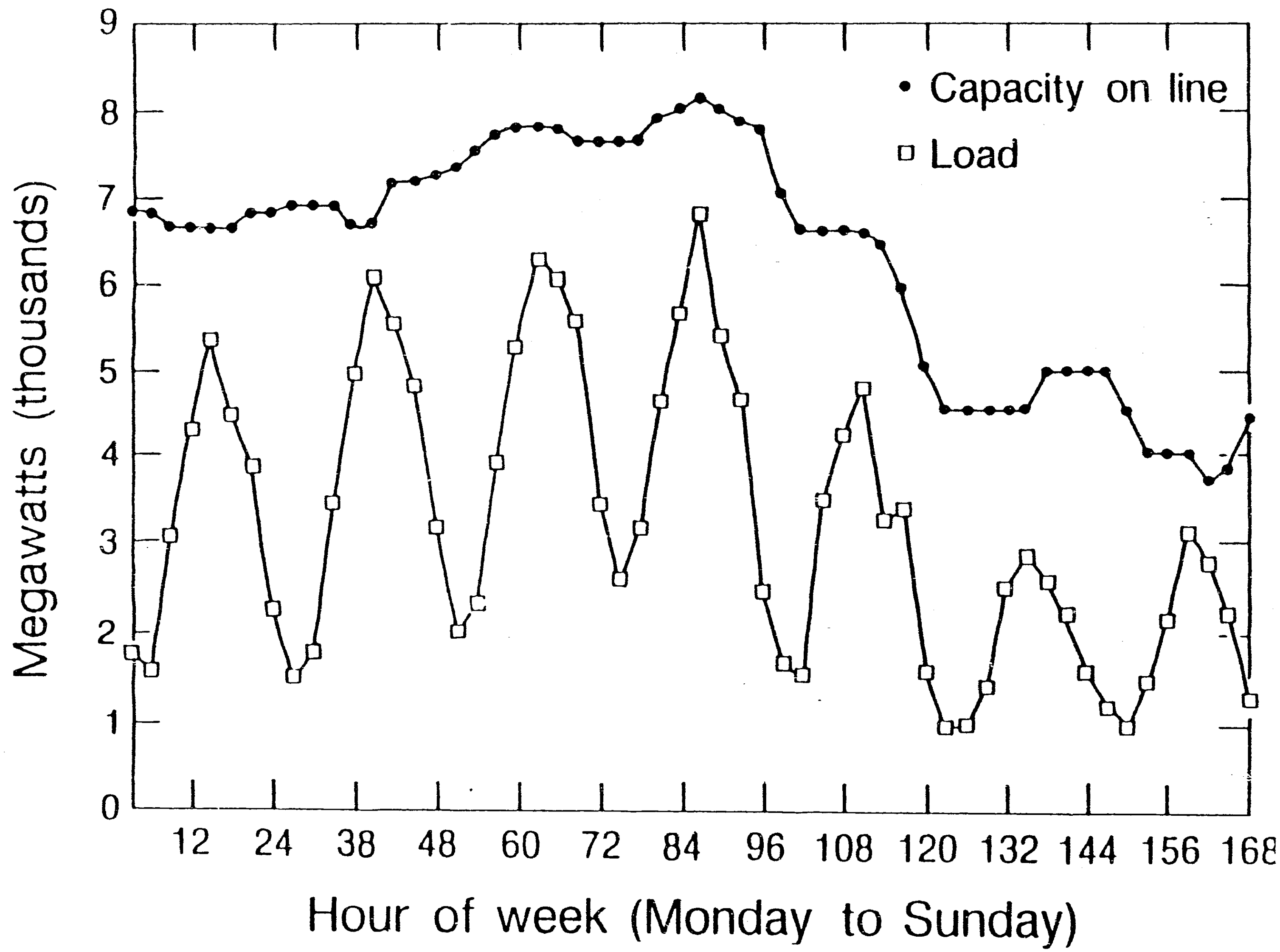
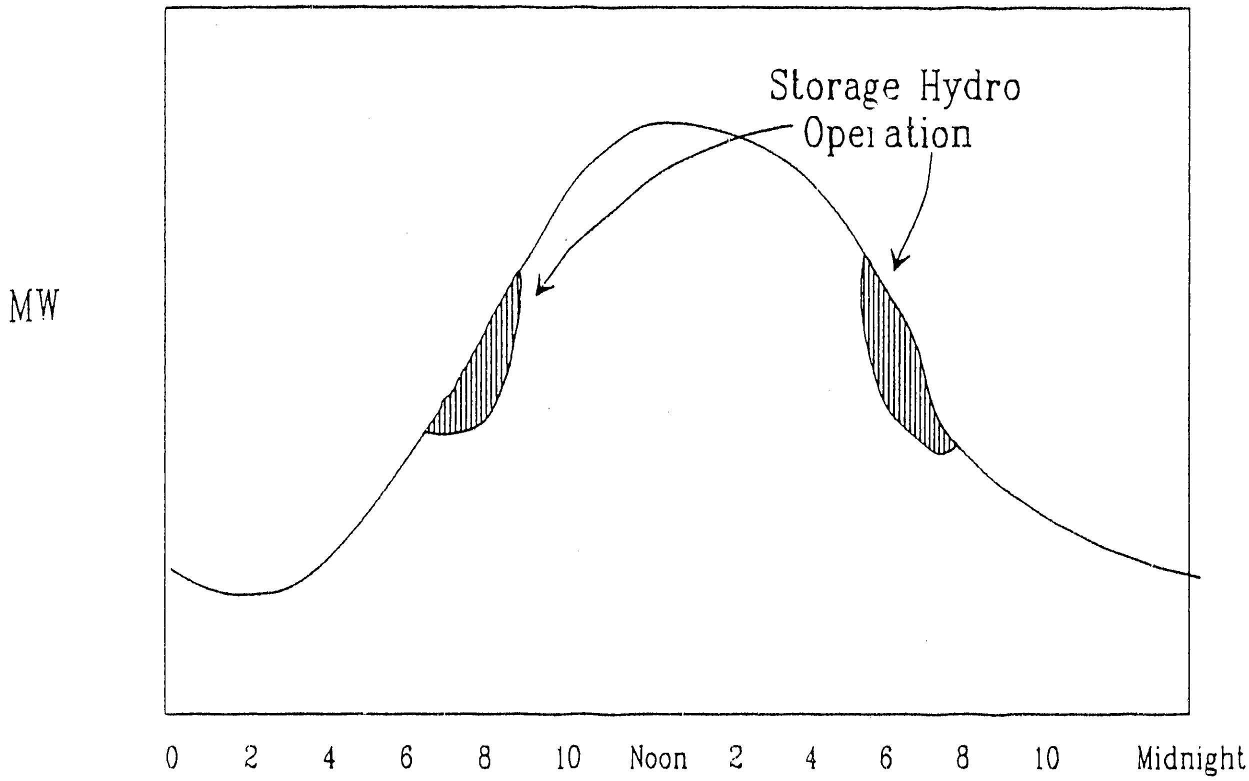


Figure 4-2
Storage Hydro Used for Ramping



4.1.2 Analytical Procedures

We distinguish four kinds of simulation programs that are used to study dispatchability in various ways. Each kind of program has certain advantages and disadvantages. In every case, the fundamental trade-off involves computational tractability versus the accuracy and completeness of the representation. It is convenient to think of the models we will describe in terms of the time horizon they encompass. Typical applications range from study periods of thirty years for long-range planning to one week for operational planning. These typical study periods are strongly related to the kind of problem for which the models are appropriate.

Long Term Optimization

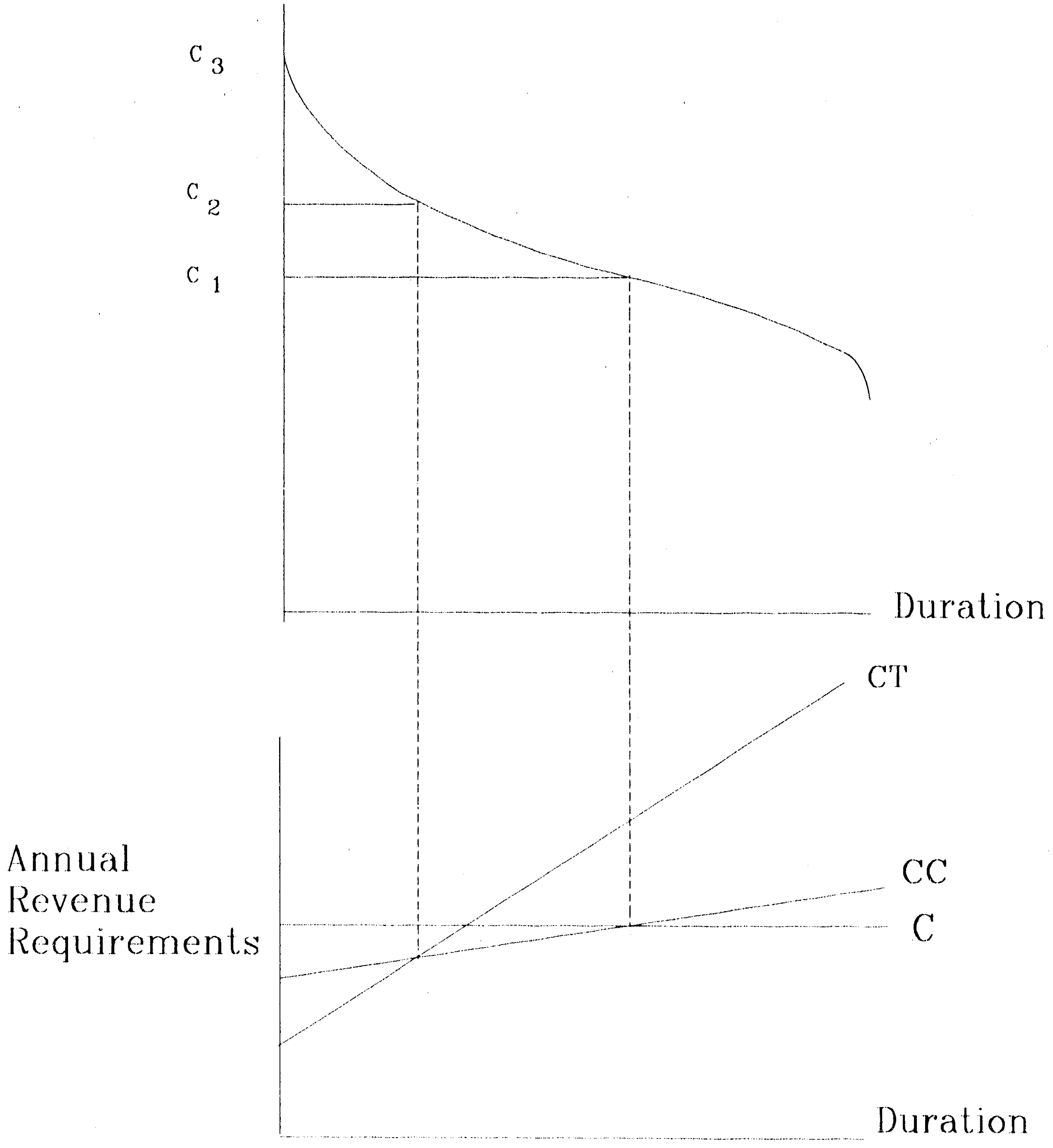
For long-range capacity expansion studies, it is common to use an optimization model that can choose economic plans over multi-year planning horizons by selecting among a number of alternative resources. Two widely used models of this kind are the EPRI model EGEAS (Caramanis, et al., 1982) and PROVIEW, developed by Energy Management Associates. Because these are large-scale problems, only the curtailment aspect of dispatchability is represented within them. There is no representation of unit commitment, and the characterization of loads makes treating the chronology problems impossible. The basic question that long range optimization models address involves the trade-off between fixed and operating costs. Plants using high cost fuels typically have lower fixed costs than plants using low cost fuels. Depending on the relative fixed and operating costs, and the structure of demand, one type of plant will be preferred over another.

Figure 4-3 shows a simple representation of how capacity expansion models incorporate curtailment into the representation of the costs of alternatives. This figure is known as a screening curve (Stoll, et al. 1989, pp. 501-505). The upper panel shows a load duration curve representation of demand, where all hourly load observations are re-ordered into a monotonically declining series from left to right. For every load level on the y-axis, the number of hours this load is met or exceeded can be read from the x-axis. The bottom panel shows cost curves for three generic alternatives. The annual fixed cost of each alternative is represented by the intercept of each line and the variable cost is the slope of the annual revenue requirements line. The points at which these lines intersect form an envelope which defines the least cost frontier. Projecting these intersection points up to the load duration curve defines the optimal mix of technologies, and their operating profiles.

This figure simplifies the optimization in a number of respects. First the picture presents the optimal mix of resources if the system could be constructed overnight. The algorithms applied to real situations must account for existing resources and their retirement over time. Secondly, fuels will not all change price at the same rate. The specific cost escalation patterns must be taken into account. As loads grow and costs change, the efficient frontier will alter. The optimal expansion plan must weigh all these factors.

Figure 4-3 does not give an accurate account of how dispatch is handled by these models. There is no representation of unit commitment. Every alternative is assumed to be available for the entire duration of the period embodied in the load duration curve. There are no start-ups or shut-downs; no minimum operating levels. Ramping cannot, in principle, be handled by models that use the load duration curve representation. Ramping is fundamentally a chronological phenomenon; it is the hour to hour load changes that count. By taking advantage of computational efficiencies associated with the load duration curve, these models lose all chronology.

Figure 4-3
Screening Curve



The end result is an economic trade-off in which only curtailment is treated and even this is approximate. The approximation is useful because curtailment is a first-order effect. The fixed cost/variable cost trade-off can only be assessed when the different levels of operation are approximated for the high variable cost resource and the low variable cost resource. These variable cost differences mean that the resources will operate differently, and that difference must be taken into account. Simple figures of merit such as the busbar cost of alternatives are useless unless all alternatives will operate in a baseload or "must-run" mode.

Production Simulation: Load Duration Curve Models

Although capacity expansion models are standard planning tools, their use is not nearly so widespread as production simulation models. The most widely used product of this kind is PROMOD III, which uses the load duration curve approach applied to representative weekday, weeknight and weekend periods for every month of the year. Production simulation models cannot perform the kind of fixed and variable cost trade-off among many alternatives that optimization offers. Instead they typically have a much greater level of detail for incorporating operational constraints into the calculation of variable costs. Production simulation models are used for fuel budgeting, contract evaluation and the comparison of a small number of resource alternatives. Unit commitment is commonly represented in these models by requiring that the initial minimum block of capacity be running in the base load segment before the remaining capacity can be dispatched.

A major distinction among the class of production simulation models involves the representation of demand. The use of the load duration curve is due fundamentally to its computational advantages. Efficient algorithms for computing production costs were first discovered in the late 1960s based on the suppression of chronological detail (Baleriaux, et al., 1967; Booth, 1972). Within this framework the commitment of units is based on a representation which assigns the minimum capacity of committed units to the baseload segment of the dispatch order and reserves the remaining capacity for merit order loading, typically in the intermediate segment. The weekend shutdown phenomenon that is illustrated in Figure 4-1 can be accommodated in programs that use the three load duration curve per month approach. In this case, one of the load duration curves represents the weekend period, and some units are removed from the dispatch list for this period. To determine the amount of committed capacity, these models typically use simple reserve margin rules.

The load duration curve based simulation models are the most widely used planning tool for mid-term problems. They typically embody a simple representation of unit commitment which dispatches the minimum capacity of a unit in the base load segment if that unit will be needed to meet a subsequent peak. Reserve margin heuristics determine this need. A unit can only be used if it has been treated this way. This representation of unit commitment enhances the reliability of these models in both fuel planning studies, where total use of fuels are at issue, and various power exchange contract studies where marginal operating costs are crucial. This representation of unit commitment can have a major effect on the estimation of short-run marginal cost (SRMC). Typically this feature will result in a lower estimate of SRMC than what would result from a simpler model of this kind without the unit commitment feature (Kahn, 1988). This occurs because unit commitment forces the dispatch of high cost minimum capacity in the baseload that would not operate there in unconstrained models. The effect of this is to force lower cost resources up the loading order "onto the margin," which lowers SRMC compared to the simple unconstrained case.

Despite the improvements available from the added detail of these models, the suppression of chronology is a basic limitation (Manhire, 1990). Many aspects of the unit commitment problem, such as minimum down times, minimum up times and start-up costs can only be treated very approximately. Ramping constraints cannot, in principle, be handled by load duration curve models. To study these issues concretely, the next level of detail is required, full chronological representation of demand.

Production Simulation: Chronological Models

The step from load duration curves to full chronology involves significant increases in computation. The first model of this kind that came into reasonably widespread use was POWRSYM, developed by the Tennessee Valley Authority (TVA). This model was originally conceived as a research and planning tool, and was designed with the specific configuration and accounting procedures of the TVA system in mind. A number of commercial products have been developed subsequently which derive from POWRSYM, retaining much of its structure, but adding proprietary features. A useful survey of chronological production simulation models is Marnay and Strauss, 1989a.

The representation of random unit outages is often treated distinctly in the chronological approach by using Monte Carlo techniques. This is a very direct way of accounting for different outage conditions facing the power system, but it increases computation time dramatically compared to the Baleriaux-Booth approach. To get an accurate picture of the expected conditions on the power system, many "draws" from the outage distribution must be simulated and then averaged together. To reduce the number of simulations necessary for accuracy, substantial interest in variance reduction techniques has emerged. These techniques allow for efficient sampling of the outage distribution (Breipohl, et al., 1990; Marnay and Strauss, 1989b; Oliveira et al., 1989). There are alternative approaches to representing outages in this framework, but they are not particularly well founded.

The treatment of unit commitment in these models is often superior to what is possible in the load duration approach. The minimum up time and down time constraints can be represented realistically, although approximations may be required in actual use. These models do not use the detailed optimization techniques that are common in the unit commitment programs used by operators to plan the actual scheduling of generation on a weekly time- scale. Rather, they apply rules of thumb for making operating decisions. The production cost framework usually involves a time period of at least one year. Often the studies for which they are used involve a period of many years.

Chronological models also represent constraints such as ramping and spinning reserve requirements.

Unit Commitment Programs

Many of the operational features we have been discussing are only treated in a systematic fashion by optimization programs that forecast efficient commitment and schedules for power systems over short time horizons (Jackups, et al., 1988, Le, et al., 1983, Merlin and Sandrin, 1983). Even these programs do not account for every issue we have discussed. Typically, the issue of random forced outages, which is important for longer range planning, is neglected by operators. The operator usually knows the state of his system in detail, so his short-run planning objective need not focus on explicit estimation of expected values assuming random outages.

While unit commitment models may give the most accurate picture of operating conditions, they are too complex to be used for long range planning. Therefore our modelling of dispatchability issues in competitive bidding will ignore this level of detail.

We summarize this discussion in Table 4-1 which broadly differentiates among these model types.

Table 4-1

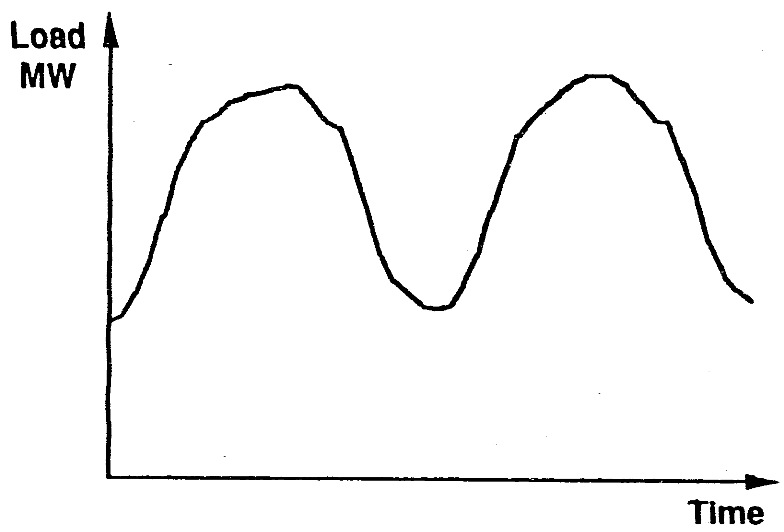
Model Types and Capabilities

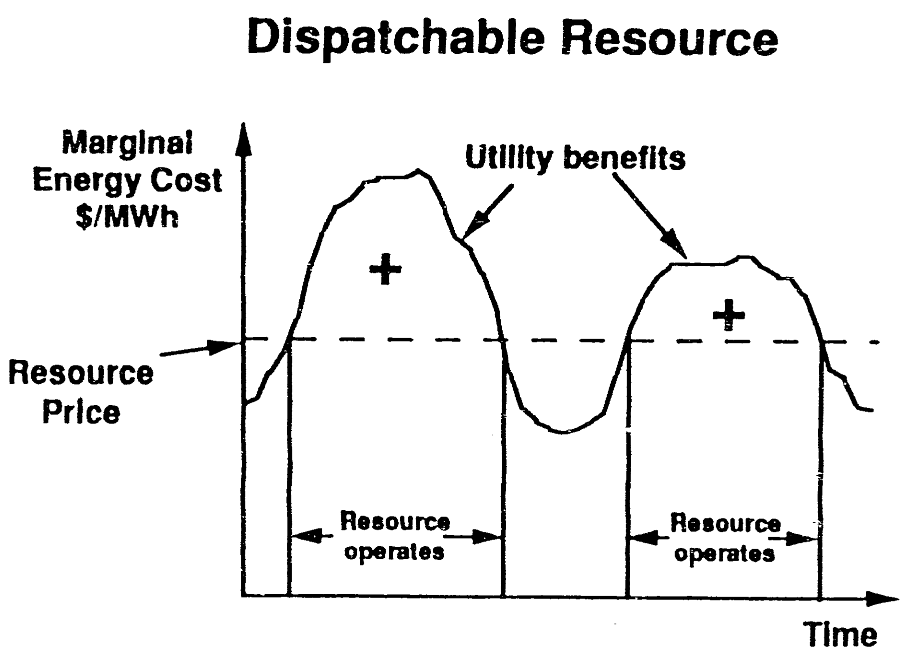
Model Type	Typical Time Horizon	Unit Commitment Representation	Outage Treatment	Fixed Cost Treatment
Long Term Optimization	10-30 years	None	Probabilistic Convolution	Integrated trade-off of many alternatives with dispatch effects
Production Simulation: Load Duration Curve	1-20 years	Reserve Margin Heuristics	Probabilistic Convolution	Exogenous two way comparisons of a limited number of options
Production Simulation: Chronological	1 year	Heuristic using minimum up/down times ramp rates spinning reserve	Monte Carlo	None
Unit Commitment	1 week	Optimized	None	None

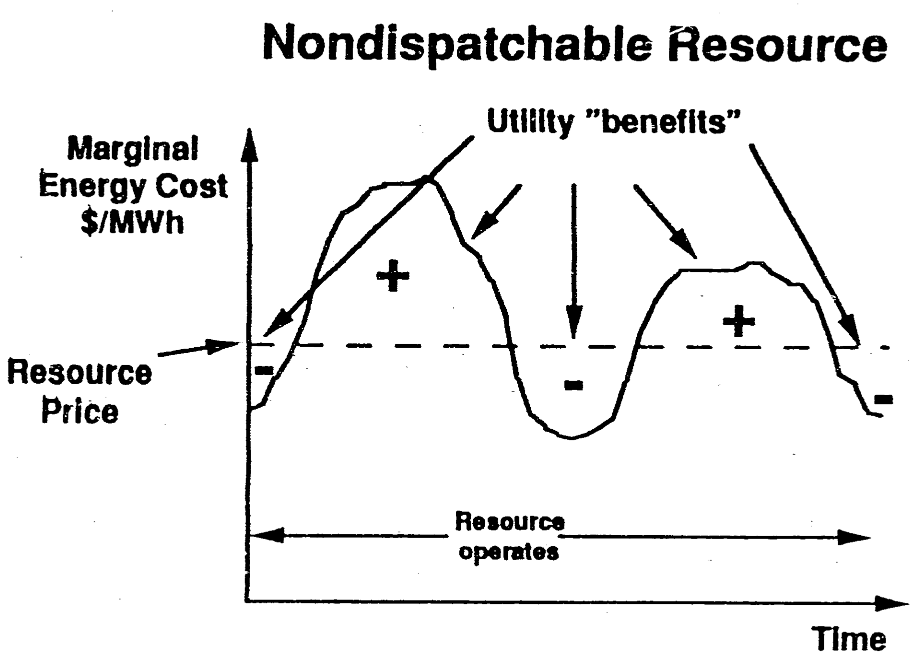
4.1.3 Preliminary Calculations

In this section we report a number of tests run using different models that express the value of dispatchability. We use a procedure that is designed to calculate an upper bound. Our approach is based on computing the costs of a given bid in two configurations, one where the bid is dispatchable and one where it is "must-run." The "must-run" condition is essentially the PURPA obligation to purchase. Until the advent of competitive bidding provided for operational flexibility, private power purchased under PURPA rules only made very limited accommodation to the dispatch requirements of utilities. QF power was treated as a baseload resource with no obligation to follow load fluctuations. The computations that we report below essentially treat the PURPA obligation as the norm, and dispatchability as a value-added product. This is not an ideal type of comparison. The PURPA norm turns out to be quite inefficient, so there are any number of ways it can be improved. It is much more difficult to specify an ideal arrangement, so we will start with the PURPA comparison as an upper bound and a qualitative guide.

Figure 4-4
Benefits of Dispatchable vs. Must-Run Operation







It is useful to describe the kind of calculation we conduct in a little more detail before characterizing the different modelling environments in which it can be performed. This will give some intuition about the kind of results we should obtain and what they mean. Figure 4-4 (PG&E, 1989) illustrates schematically the difference in value between a dispatchable resource and a "must-run" (or non-dispatchable resource).

The must-run resource has lower value than the dispatchable resource because the former may operate at times when its variable cost exceeds the marginal opportunity cost of the power system. This is represented by the negative area on the graph in the lower left hand corner of the figure. The dispatchable resource does not operate during such periods. Therefore when it operates it only produces benefits, which are represented here by marginal opportunity costs above the variable cost of the resource. The balance of positive and negative areas for the "must-run" case will shift with the variable cost of the resource. When variable costs are low (relative to opportunities) then the negatives will be smaller and the positives greater than the case where variable costs are high.

We should expect, therefore, that the value of dispatchability, relative to overall resource cost, will increase with the variable cost of the resource. The basic intuition is clear. If a resource has low variable cost, we will want to use it frequently and steadily. The value of flexibility is low in this case because we have little incentive to ration the use of such resources. When variable cost is high, on the other hand, we are paying a premium for flexibility and will want to use it.

Implementing this approach is possible in a number of different modelling environments. We describe two cases below using very different models. The results from each method are reasonably consistent.

Optimization Framework

We have argued previously that optimization models are the preferred method for evaluating dispatchability in principle (Kahn, et al., 1989). The practical use of these models can present difficulties, and they are not adapted to all aspects of the dispatchability value problem. Nonetheless the calculations sketched above can be implemented neatly in this framework.

We specify the problem in the following manner. We reduce the capacity expansion problem to a choice between two alternatives. One is a dispatchable bid characterized by a capacity (MW), a levelized capacity price ($/kW-yr), and a variable price ($/MWh, escalating with an appropriate fuel cost index). The other alternative has the same parameters, except that it is constrained to be a must-run unit. Given these two choices, the model will always choose the dispatchable version unless the variable price is so low that the alternative will never be curtailed for economic reasons.

The calculation proceeds by lowering the levelized capacity price of the must-run alternative. At some point, when this price becomes low enough, the model will choose the must-run alternative over the dispatchable alternative. The discount from the original levelized capacity price becomes the levelized value of dispatchability. We repeat this procedure for a range of alternatives. Results are given in Table 4-2. These calculations are made using the EGEAS model on a data set representing the Virginia Power 1988 Solicitation. Much of the background data and further references are given elsewhere (Kahn, et. al., 1989). The natural gas price forecast assumes nominal escalation of gas costs averaging 6% per year (equivalent to 1% real price escalation). Dispatchability value is shown in column 4 measured in $/kW-yr. Column 5 normalizes these values to the capacity price of the resource.

Table 4-2
Dispatchability Value Relative to Must-Run Norm

Plant	Capacity Price ($/kW-yr)	1988 Variable Price (mills/kWh)	1997 Output (Cap. Fctr.)	Value ($/kW-yr)	Value/Capacity Price
Coal 29	240	17.3	72%	5	0.02
Coal 12	191	18.3	70%	8	0.04
Coal 5	188	18.7	59%	9	0.05
Coal 26	194	19.2	56%	11	0.06
Gas 4	97	25.9	56%	74	0.76
Gas 1	120	26.3	51%	80	0.66
Gas 6	97	31.0	39%	131	1.36

Table 4-2 shows a sharp discontinuity in results between the values calculated for the coal based alternatives and the gas based alternatives. Two important factors contribute to this result. Most importantly, the cost of gas is so much higher than the cost of coal that when gas alternatives are forced to operate in must-run mode they are very expensive. A lesser contributor to these results is the higher availability of gas units compared to coal. The must-run output for the coal plants is a capacity factor of 79.5%, compared to 89.5% for gas. This means that an even greater capacity price discount is necessary for the gas alternatives because they operate about 12% more per MW than the coal alternatives (1.125 = 89.5/79.5).

Static Simulation

An alternative approach to this same kind of calculation can be made using more static simulation methods. For this case we rely on the most sophisticated self-scoring bid evaluation method introduced to date, the Jersey Central Power and Light (JCPL) price scoring spreadsheet (JCPL, 1989). This spreadsheet uses production simulation results to create a price scoring system that estimates the capacity factor of dispatchable projects based on their variable costs, and associates with this estimate a specific avoided cost corresponding to that capacity factor. The JCPL method is discussed at greater length in Section 2 above.

The benchmark of equality that we use for our examples is projects receiving the same price score under the JCPL method. As indicated in our more extensive discussion, there are details of the price scoring procedure which are not correct. For our purposes, which are only order of magnitude type approximations, we can neglect these issues. Just as in the optimization context, we consider two versions of the same project, one which is dispatchable, one which is must-run. To achieve equal price scores, the must-run project must be discounted.

We ran two cases, one based on coal and one based on gas. The coal project was priced at a levelized price of $200/kW-yr for capacity and $24/MWh (escalating at a coal cost index) for energy. In its first year of operation this project was projected to operate at 43% capacity factor. Its price score under the JCPL method is 90% of avoided cost. To get a must-run project with the same energy cost to also achieve a score of 90% of avoided cost, the levelized capacity payment must be discounted to $187.66/kW- yr. This makes the value of dispatchability $12.34/kW-yr ($200- $187.66 = $12.34) for this case, or 6.17% of the levelized capacity price (($12.34/$200) = 0.0617). This example is most comparable to the Coal 26 alternative in Table 4-2.

Our second case is based on gas. Here we use a project which approximates the avoided unit in the JCPL evaluation system. It is a combined cycle plant priced at a levelized capacity cost of $130/kW-yr and $29.3/MWh (escalating at a gas cost index) for energy. At these prices, the JCPL scoring method rates this project at 103% of avoided cost. To get a must-run project based on the same energy price to achieve the same score, we discount the capacity price to $76/kW-yr. This makes the value of dispatchability $54/kW-yr for this case, or 41.5% of the levelized capacity price.

These two cases give the same kind of qualitative results that are shown in Table 4-2. The JCPL estimates are a bit higher for coal and a bit lower for the gas case compared to the Virginia Power examples, but within the same range. The differences are due to assumptions about gas costs, modelling procedures, etc., which for these qualitative purposes are relatively unimportant.

The preliminary conclusion suggested by these results is that dispatchability adds relatively little to the value of coal bids, but is fundamentally important for gas bids. These results quantify the intuitive notion that low variable cost resources should be run at high capacity factor to justify their fixed costs. Conversely, high variable cost resources must have operational flexibility to justify their costs. With this background, we begin the more explicit study of dispatchability value.

4.2 Test Systems and Procedures

To study dispatchability attributes in detail we explore a range of simulation tools, and apply them to our entire spectrum of attributes. The strategy we employ involves both issues involving modelling techniques as well as the examination of particular dispatchability attributes. The discussion in Section 4.1.2 indicated that there is no one modelling framework that is adequate to addressing all the questions relevant to evaluating bids that offer operating flexibility. At one end of the spectrum, long range planning models with optimization capability allow the trade-off between fixed and operating costs to be addressed. Evaluating the trade-off between fixed and variable costs comes at the price of imprecision on the operating side. In this section we develop an approach to measuring how large the imprecision may be in using long range models.

The basic paradigm implicit in our approach is that bid evaluation is fundamentally a multi-stage process. Initially bids are screened to reduce the number of offers to a relatively small set that will be analyzed in detail. This screening process necessarily uses relatively simple methods because of time and resource constraints. We want to know what is being missed through the use of simpler methods; how important are the additional details? Inevitably this question can only be answered by comparing the simpler with the more detailed methods. We will explore these questions using two models that span the range of available approaches. On the detailed side we use the EPRI BENCHMARK model (Jenkins, 1989). This is a chronological simulation model incorporating many operating constraints. The cost of simulating operating detail is the limitation of a one year horizon. At the other end of the spectrum we use the EPRI long range planning model EGEAS (Caramanis, et. al, 1982). We will take advantage of the multi-year optimization capability in this model.

4.2.1 Characterization of Base System

The base system we use for our analysis is a hybrid which is designed to allow examination of constrained operating environments. Figure 4-5 is one simple illustration of how we incorporate the minimum load phenomenon into our test system. This figure shows an annual load duration curve with baseload resources filled in from the bottom up. The figure shows that the system load is below 5000 MW for approximately 3[illegible]% of the year. Baseload resources in the generating mix include 2000 MW of nuclear, 1000 MW of must-take Qualifying Facility resources, and 1000 MW of run-of-river hydro that operates at this level all year around. We represent the nuclear capacity by its expected value of 1500 MW, accounting for forced outages. The outages for hydro are essentially zero, and we ignore them also for the QFs.

The next 950 MW represents the minimum operating capacity of the baseload fossil units which have the lowest operating costs and the least flexibility. We use the sum of minimum up time and minimum down time to define a quantity we call minimum cycle duration. For these units, this is 144 hours. It is at the region of the curve where this capacity intersects the loads that the problem of excess baseload generation, or minimum load occurs. A representation such as Figure 4-5 is only suggestive. The low load periods typically occur in the midnight to 7AM segment of the diurnal load swing (see Figure 4-1). The amount of committed capacity, hence the magnitude of long cycle duration capacity committed in the baseload will vary with the forecasted weekly peak load. The extent to which the utility can rely on combustion turbines to meet the weekly peaks will also strongly influence the amount of committed capacity. Despite these complexities (which require simulation models to track in detail), Figure 4-5 does show the basic origin and magnitude of the minimum load problem.

Table 4-3 is a BENCHMARK annual output summary for the thermal generation on our test system. The capacity mix includes, beyond the nuclear, QF and hydro resources, ten coal plants totaling 2500 MW, ten gas-fired generators totaling 2500 MW, two 500 MW oil-fired plants, and ten combustion turbines totaling 1000 MW. For simplicity, we assume no maintenance schedule. This table says a number of interesting things. It includes a column labelled "Start Ups," which gives an explicit account of how the unit commitment process has worked in a particular simulation. It is worth a brief glimpse at this column to characterize the dispatch of our test system in the base case.

One simple definition of baseload resources that Table 4-3 provides is those units with 12 starts or less. If a unit is run all year, restarts after forced outages will consume about 12 starts. By this definition, Coal 1-4, Gas 1 and 2, and Oil 1 and 2 are baseload units.

At the other end of the spectrum, the combustion turbines (CT) show an enormous number of starts. CT 1-4 start more than 260 times, which is equivalent to once every weekday of the year. These results do not comport with actual experience. Electric utility dispatchers do not often place substantial reliance upon CTs. A recent survey of technology and utility operating practice cited 150 starts per year as the high end of reasonable estimates (Hayes, 1990). The Commonwealth Atlantic contract discussed above in Section 1.2.6 also listed 150 as the maximum number of starts per turbine. In the current state of the modelling art, such constraints cannot be imposed.

Figure 4-5
Load Duration Curve for Sample Utility

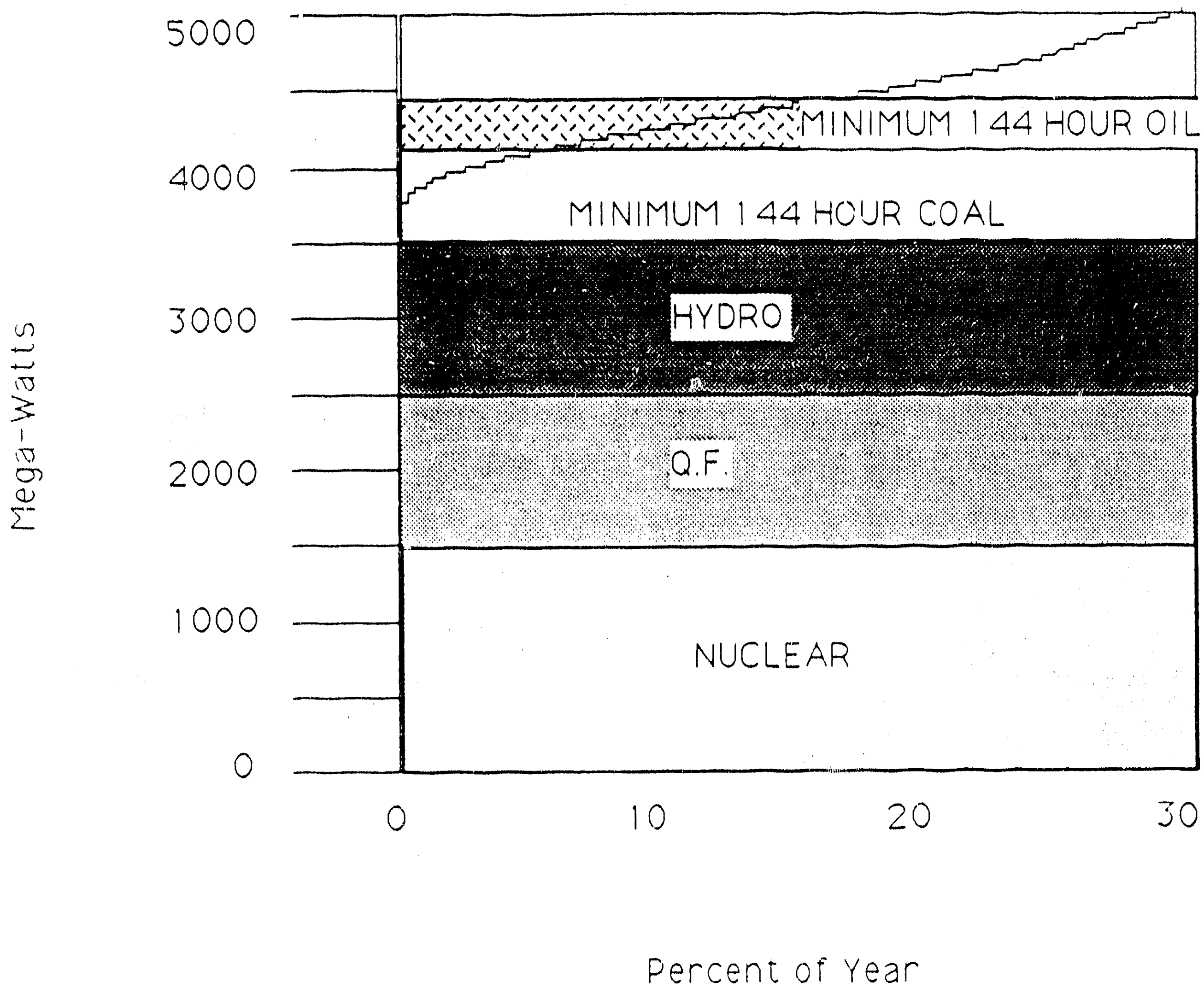


Table 4-3

---- BASE CASE - Sat May 26 17:12:59 PDT 1990

THERMAL UNIT DATA BY UNIT
REPORT PERIOD : 1 1 90 THROUGH 12 30 90
(AVERAGE FOR ALL DRAWS)

UNIT	NAME	CAP MW	CAP FCT(%) MEAN	CAP FCT(%) STND DEV.	NO.OF LIKE UNITS	ENERGY (GWH)	FUEL USAGE MBTU (X1000)	FUEL USAGE UNITS (X1000)	FUEL USAGE STD UNIT	HT RATE BTU/KWH	START UPS	OPERATING COST FUEL COST(K$)	OPERATING COST VAR O&M (K$)	OPERATING COST FIXED COST(K$)	OPERATING COST START UP COST(K$)	TOTAL COST(K$)	TOTAL $/MWH
1	NUKE01	1000.	75.6	5.4	1	6602.4	66024.2	66024.2	MBTU	10000.	9.	66024.21	0.00	0.00	0.00	66024.21	10.00
2	NUKE02	1000.	75.8	6.2	1	6619.2	66192.2	66192.2	MBTU	10000.	8.	66192.21	0.00	0.00	0.00	66192.21	10.00
3	QF01	500.	100.0	0.0	1	4368.0	43680.1	43680.1	MBTU	10000.	0.	174720.59	0.00	0.00	0.00	174720.59	40.00
4	QF02	500.	100.0	0.0	1	4368.0	43680.1	43680.1	MBTU	10000.	0.	174720.59	0.00	0.00	0.00	174720.59	40.00
5	COL01	500.	62.1	4.2	1	2713.	30170.7	30170.8	MBTU	11119.	9.	45256.12	0.00	0.00	172.00	45428.12	16.74
6	COL02	500.	62.5	3.8	1	2729.9	30233.2	30233.2	MBTU	11075.	9.	45349.80	0.00	0.00	180.00	45529.80	16.68
7	COL03	300.	67.7	3.4	1	1774.8	20447.8	20447.8	MBTU	11521.	5.	32716.41	0.00	0.00	92.75	32809.16	18.49
8	COL04	300.	67.7	2.8	1	1773.3	20397.8	20397.8	MBTU	11503.	6.	32636.55	0.00	0.00	101.50	32738.05	18.46
9	COL05	200.	40.4	2.7	1	705.5	8785.8	8785.8	MBTU	12453.	27.	14496.61	0.00	0.00	411.00	14907.61	21.13
10	COL06	200.	42.3	1.6	1	738.6	9209.3	9209.3	MBTU	12468.	28.	15195.40	0.00	0.00	414.00	15609.40	21.13
11	COL07	150.	40.8	4.3	1	534.3	6006.9	6006.9	MBTU	11242.	29.	10211.72	0.00	0.00	361.25	10572.97	19.79
12	COL08	150.	44.3	2.1	1	580.8	6504.9	6504.9	MBTU	11201.	30.	11058.28	0.00	0.00	376.25	11434.53	19.69
13	COL09	100.	15.5	2.8	1	135.6	1586.4	1586.4	MBTU	11700.	37.	2776.23	0.00	0.00	925.00	3701.23	27.30
14	COL10	100.	16.8	2.7	1	146.7	1720.3	1720.3	MBTU	11727.	40.	3010.61	0.00	0.00	1005.00	4015.61	27.37
15	GAS01	750.	35.1	3.0	1	2301.1	27201.0	27201.0	MBTU	11821.	10.	65282.32	0.00	0.00	360.50	65642.82	28.53
16	GAS02	750.	39.7	4.3	1	2598.9	29734.1	29734.1	MBTU	11441.	10.	71361.73	0.00	0.00	332.50	71694.23	27.59
17	GAS03	200.	27.8	3.8	1	485.4	4875.3	4875.3	MBTU	10045.	14.	11700.65	0.00	0.00	170.00	11870.65	24.46
18	GAS04	200.	28.8	3.3	1	503.4	5044.2	5044.2	MBTU	10021.	13.	12105.98	0.00	0.00	161.25	12267.23	24.37
19	GAS05	125.	13.0	1.9	1	142.2	1653.5	1653.5	MBTU	11629.	13.	3968.45	0.00	0.00	94.50	4062.95	28.57
20	GAS06	125.	13.6	1.7	1	148.7	1731.3	1731.3	MBTU	11644.	13.	4155.08	0.00	0.00	96.00	4251.08	28.59
21	GAS07	100.	13.8	2.4	1	120.5	1465.5	1465.5	MBTU	12163.	14.	3517.19	0.00	0.00	71.00	3588.19	29.78

Table 4-3 (continued)

---- BASE CASE - Sat May 26 17:12:59 PDT 1990

THERMAL UNIT DATA BY UNIT
REPORT PERIOD : 1 1 90 THROUGH 12 30 90
(AVERAGE FOR ALL DRAWS)

			CAP FCT(%)		NO.OF		-----FUEL USAGE----					------OPERATING COST------					
UNIT	NAME	CAP MW	MEAN	STND DEV.	LIKE UNITS	ENERGY (GWH)	MBTU (X1000)	UNITS (X1000)	STD UNIT	HT RATE BTU/KWH	START UPS	FUEL COST(K$)	VAR O&M (K$)	FIXED COST(K$)	START UP COST(K$)	----TOTAL---- COST(K$)	$/MWH
22	GAS08	100.	14.2	1.7	1	124.2	1506.5	1506.5	MBTU	12125.	13.	3615.62	0.00	0.00	66.50	3682.12	29.64
23	GAS09	75.	14.0	2.1	1	92.0	1028.4	1028.4	MBTU	11174.	20.	2468.13	0.00	0.00	49.50	2517.63	27.36
24	GAS10	75.	14.7	2.3	1	96.0	1072.9	1072.9	MBTU	11173.	21.	2574.99	0.00	0.00	52.75	2627.74	27.36
25	OIL01	500.	16.2	2.0	1	707.3	7939.1	7939.1	MBTU	11225.	12.	19053.91	0.00	0.00	295.00	19348.91	27.36
26	OIL02	500.	16.7	3.3	1	728.0	8108.1	8108.1	MBTU	11138.	12.	19459.47	0.00	0.00	310.00	19769.47	27.16
27	CT01	150.	25.3	2.1	1	331.9	3322.0	3322.0	MBTU	10009.	296.	12789.79	0.00	0.00	0.00	12789.79	38.53
28	CT02	150.	29.9	1.5	1	391.6	3919.8	3919.8	MBTU	10009.	319.	15091.06	0.00	0.00	0.00	15091.06	38.53
29	CT03	125.	18.0	1.0	1	196.6	2164.4	2164.4	MBTU	11008.	262.	8332.95	0.00	0.00	0.00	8332.95	42.38
30	CT04	125.	21.1	1.3	1	230.8	2540.3	2540.3	MBTU	11008.	273.	9780.21	0.00	0.00	0.00	9780.21	42.38
31	CT05	100.	12.9	1.3	1	112.9	1355.4	1355.4	MBTU	12007.	221.	5218.32	0.00	0.00	0.00	5218.32	46.23
32	CT06	100.	14.[illegible]	1.4	1	128.7	1545.8	1545.8	MBTU	12008.	232.	5951.30	0.00	0.00	0.00	5951.30	46.23
33	CT07	75.	9.2	1.6	1	60.0	780.6	780.6	MBTU	13007.	179.	3005.34	0.00	0.00	0.00	3005.34	50.08
34	CT08	75.	9.8	1.6	1	63.9	831.1	831.1	MBTU	13007.	186.	3199.59	0.00	0.00	0.00	3199.59	50.08
35	CT09	50.	6.7	1.3	1	29.4	411.3	411.3	MBTU	14005.	132.	1583.40	0.00	0.00	0.00	1583.40	53.92
36	CT10	50.	7.1	1.7	1	31.2	436.9	436.9	MBTU	14006.	148.	1682.21	0.00	0.00	0.00	1682.21	53.92
SYSTEM TOTAL :		10000.	49.7	0.2		43415.1	463307.3					980263.1	0.0	0.0	6098.2	986361.4	22.72

4.2.2 Upper Bounds on the Value of Dispatchability

To estimate the maximum value of dispatchable resources, we perform initial tests using BENCHMARK and EGEAS that are oriented to hydro resources. The motivation for these tests is Figure 4-2, which shows that hydro can be more valuable in a ramping operation than in a purely peak shaving one. We also use this setting to calibrate the EGEAS representation of our test system with BENCHMARK. BENCHMARK is cumbersome to use for multi-year evaluation. But we want to know how much larger its measurement of single year effects may be than those in EGEAS, so that when we make multi-year EGEAS analyses, or similar use of any equivalent model, we will be able to adjust them.

The first test we perform is to shift some fraction of the hydro energy that is dispatched in the baseload into the fully flexible storage mode. This requires increasing the total hydro capacity. We perform these tests under the constraint that all hydro energy shifted into the storage mode will operate at 50% capacity factor. The results of this test are remarkable. The operating cost reductions which occur from this shift are normalized to the hydro capacity increase, so that we can express dispatchability value on a $/kW basis. The BENCHMARK simulations are summarized in Table 4-4. They show values of as much as $145/kW-yr at small levels to $70/kW-yr for very large increments (i.e. 1000 MW).

Table 4-4

Storage Hydro Capacity Value (BENCHMARK)

MW Added	$/kW-yr
50	145
100	96
250	92
500	85
1000	70

Parallel tests were performed in EGEAS. It became immediately apparent that without the unit commitment and other constraints, EGEAS dispatch was already so flexible that additional dispatch value was small. A typical value was in the range of $15/kW. To improve the representation we took advantage of the EGEAS "must-run" feature to approximate unit commitment. By designating the units in Table 4-3 with 14 or fewer starts as must-run for their minimum capacity, we can give a rough approximation to unit commitment. This amounts to Gas units 1-8 and Oil 1-2. The results of these runs were dispatchability values in the $30-40/kW-yr range. Even this approximation does not really capture the effect of shifting capacity to storage hydro. One of the benefits of such a shift is the reduced need to commit expensive thermal capacity. We ran one test corresponding to the case of 500 MW of storage hydro. With no change in the "must-run" list, the hydro value was $29.90/kW-yr. When we add the storage hydro and delete a 500 MW unit (Oil 2) from the "must-run" list, the value increases to $43.62/kW-yr.

We conclude from these tests that the simplified simulation misses a substantial fraction of dispatchability value, on the order of 1/2 to 2/3 of what the more detailed model finds. Subsequent tests will confirm this estimate. To address the question of adjusting what we learn from detailed simulation to use in more simple models, we examined in more detail what the long-run, multi-year effects of our hydro shift cases would look like in EGEAS. We ran a set of twenty-one year simulations in EGEAS corresponding to our case in which 500 MW of storage hydro capacity is added to the base system. Four fuel price scenarios were simulated. In one case all fuels escalated in cost at an annual rate of 5%. Three other cases examined 1%, 2% and 3% real escalation rates for oil and gas. Table 4-5 summarizes the results.

Table 4-5
Multi-Year Effects of Fuel Price Escalation on
Storage Hydro Capacity Value (EGEAS)

Fuel Price Escalation (%/yr)	Multi-Year Value (PV $/kW)	Annuity ($/kW-yr)	Levelization
5% All fuels	372.80	43.10	1.441
6% Oil/Gas	439.50	50.81	1.669
7% Oil/Gas	516.08	59.67	1.996
8% Oil/Ga	602.61	69.67	2.330

The second column in Table 4-5 shows the present value of the multi-year cost changes (at a 10% discount rate) normalized to the 500 MW of storage hydro capacity added. The third column expresses the annual annuitized equivalent of the column two values. These are comparable to the single year estimate of $29.90/kW referred to above. The column labelled Levelization is just the ratio of the column three value to the single year estimate of $29.90/kW. Readers familiar with the arithmetic of levelized cost calculations will recognize the column three values as being very close to the standard levelization factors used in engineering economic calculations and collected in handbooks such as the EPRI Technical Assessment Guide (volume 3). The import of Table 4-5 is that single year estimates of dispatchability attribute values can be simply scaled up to levelized values useful for long term analysis by simple use of standard levelization factors. So, for example the the BENCHMARK estimate of storage hydro value for 500 MW in Table 4-4 of $85/kW is equivalent to approximately $170/kw-yr levelized if the real escalation rate of oil and gas costs is assumed to be 7%/yr over a twenty year horizon.

4.3 Attribute Valuation

In this section we report the results of a number of BENCHMARK tests of the cost implications associated with adding operating constraints to the test system described above. These tests are designed to estimate the economic burden of operating constraints which we have found in the review of contracts (Section 1.2). Because BENCHMARK simulates only one year of operation, we discuss how the simulation results might be used to adjust lifecycle cost estimates. The three attributes we discuss are: (1) minimum operating capacity, (2) minimum operating time (and minimum shutdown duration), and (3) ramp rate constraints. The principal economic effect comes from the first attribute.

4.3.1 Minimum Operating Capacity

The motivation for testing this feature comes primarily from the Doswell contract (Section 1.2.4) and from the Vista/Paulsboro contracts (Section 1.2.9). In both cases, the projects are specified to operate only between 80% and 100% of contract capacity when they are running. The utility in both cases does have the right to shut the projects down and direct them to start up; i.e. commitment rights, subject to specified start-up and shut-down times. The Cogen Technologies contract does not give the utility commitment rights, but does allow curtailment to 82% of contract capacity during weekdays and 47% on weekends. The tests we perform are aimed at the case where units are committable but have limited curtailment. We sample a range of cases for minimum capacity, starting at 20% of total capacity which we consider as an ideal base case. Results of the simulations are shown in Tables 4-5 for gas-fired units and 4-6 for coal-fired units. The gas cases are based on highly efficient combined cycle technology, such as that expected to be used by the Doswell project and the TECO Power Services project (Section 1.2.5). The heat rates used to represent this technology are approximately those shown in Table 1-3 above.

Table 4-6

Summary of Gas Minimum Capacity Cases: Cost Penalties

		Single Year Results ($/kW/yr)	20 year Levelized Cost @ 2% real escalation
% min. Capacity	1 x 200 MW	1 X 750 MW	1 x 750
20	0	0	0
40	6	6	12
60	14	14	28
80	19	22	44

Table 4-6 shows tests for two unit sizes one at 200MW one at 750 MW. There appears to be only a slight dis-economy of scale for the larger unit. To translate the annual values to 20 year levelized costs reflecting 2% real gas price escalation we use a levelization factor of 2 (see Table 4-5).

Table 4-7 shows corresponding results for coal-fired units. We show results for three configurations, a single 100 MW unit, a single 500 MW unit and two 500 MW units. To translate the annual values to 20 year levelized costs reflecting zero real price escalation we use a levelization factor of 1.44 (see Table 4-5). It is reasonable to assume zero real cost escalation for coal. This is the indexation, for example, in the Vista/Paulsboro contracts.

Table 4-7

Summary of Coal Minimum Capacity Cases: Cost Penalties

		($/kW/yr)		20 year Levelized cost at 0% real escalation
% min. Capacity	1 X 100 MW	1 X 500 MW	2 X 500 MW	2 X 500 MW
20	0	0	0	0
40	6	6	6	9
60	13	11	12	17
80	18	16	18	26

To put these results into perspective we should normalize them to some expected values to annual levelized costs for these technologies. This will give a better measure of the economic burden imposed by operating restrictions. It is convenient to make use of the example offered in detail in Section 2.4 above; in particular, Tables 2-1 and 2-2. In that table we calculated levelized annual costs for a representative efficient gas and coal projects. We reproduce those estimates in Table 4-8 and add the cost penalties calculated above for the 80% minimum capacity cases. For the gas case we add an additional variation representing a situation in which the gas project operates for 4500 hours instead of the 3000 hours/year assumed in Tables 2-1 and 2-2.

Table 4-8

Cost Burden of 80% Minimum Capacity

	Levelized Annual Cost[a] $/kW/yr	Operating Penalty $/kW/yr	%
Gas			
3000 hrs/yr	354	44	12.4
4500 hrs/yr	451	44	9.8
Coal	541	26	4.8

[a] Table 2-2, 4500 hr. gas case scale up.

The results show that the cost burden of inflexibility is proportionally higher for the gas case than the coal case. It is in the 10-12% range for gas, and about 5% for coal. This is a more refined version of our initial highly approximate estimates contained in Table 4-2. The qualitative message is still the same. They value of premium fuels such as gas lies in their flexibility. Operating restrictions which limit that flexibility have cost penalties, which should be considered in the competitive evaluation of bids from private suppliers. A final note on modelling is important. The cost penalties reported in Tables 4-5 and 4-6 were not detectable in EGEAS. When similar cases were simulated in that model, we found essentially no cost effect. This has important implications for bid evaluation strategy, which will be outlined in our conclusions and recommendations below.

The calculations summarized in Tables 4-6 through 4-8 assume low gas prices and smooth escalation over time. As a sensitivity test we consider the case where oil and gas prices are substantially higher at the outset of the analysis. In particular, we re-run two of the cases from Tables 4-6 and 4-7 with gas prices assumed to be $5/million Btu and oil prices assumed to be $6/million Btu, just over twice their original level. The results of these runs are summarized in Table 4-9. We consider only the most extreme case, the 80% minimum capacity case compared to 20% minimum capacity. While the simulations show generally increased costs compared to the original results, the effect is disproportionate for the gas case. The single year penalty increase from $16/kW for coal to $22/kW, or about 37%. For gas the increase is from $22/kW to $76/kW, or about 3.5 times.

Table 4-9: Minimum Capacity Cost Penalty
High Oil and Gas Cost Case

	Single Year Penalty
500 MW Coal Unit	\$22/kW
750 MW Gas Unit	\$76/kW

These sensitivity results indicate that estimates such as those in Table 4-8 may considerably under-state the cost of high operating levels for premium fuels. The single year result for gas is almost twice as high as the twenty year levelized result. Put another way, this result shows a penalty that is more than 60% of the Doswell capacity payment. Doswell is the relevant comparison because that contract embodies the constraint we are analyzing. At high gas prices, the 80% minimum operating level substantially reduces the value of this contract.

4.3.2 Other Constraints

We also test the effect of minimum up and down times and ramp rate limits. The former constraint addresses how long a unit must operate once it is committed, and how long it must be off before it is turned back on. We take as the base case a twelve hour minimum up time and down time. Most of the contracts specify conditions of this kind in terms of how long it takes a unit to start and how long to shut down. Twelve hours is a typical value for these parameters. The results show minor cost implications associated with imposing longer startup and shutdown duration requirements.

Ramp rate constraints lie at the limit of detectability in BENCHMARK. The tightest constraint on ramping we have found is the SCE 5 year contract with SMUD discussed in Section4.1.1 above. In that case, the limit of 1.5 MW/minute is equal to 30% of contract capacity per hour. In the contracts reviewed in Section 1.2 only two specified a ramp rate constraint. Commonwealth Atlantic limits ramping to 5MW/minute, which is more than 100%/hour. Multitrade specifies a limit that is even more rapid, 2.5%/minute. Since BENCHMARK only works with hourly load ch ges, we cannot examine limits in the range specified by Multitrade. To examine the ramping attribute with any more precision would require going to the next level of analytical power, the unit commitment program. These are so computationally intensive that their typical time horizon is one week.

Table 4-10 shows the results of tightening the ramping constraint from 100% of capacity per hour down to 25%. The results for both coal and gas-fired units are essentially similar, and virtually indistinguishable from zero.

Table 4-10

Summary of Ramp Rate Cases

	Coal ($/kW/yr)		Gas	
% ramp/hr.	1 X 100 MW	1 X 500 MW	1 X 100 MW	1 X 750 MW
100	0	0	0	0
50	1	0	0	0
25	1	0	1	0

On this basis we conclude that ramping effects should be ignored in bid evaluation, unless the conditions on particular systems are known to be more binding than the test system examined here. The cases where ramping may be more important could be municipal or government owned systems which purchase partial requirements power. These systems are apt to be smaller than our test case system, and with fewer units they might be more constrained. Due to the relatively large size of our test system, it appears that ramping situations can be adequately covered by spreading the burden over many units.

4.3.3 Synergistic Effects

Because the minimum load problem is an issue at the system level, it is useful to approach its solution in that context. In this section we show that there are synergistic economies which can be realized by making minimum load fixes to existing resources. We conduct the analysis by examining two kinds of changes to our base case system. These are called "refurbishment" and "replacement." The former involves improvements to Coal Units 1 and 2 such as reduced minimum up and down times and reduced minimum operating capacity. The replacement cases involve substituting new efficient 200 MW units for the least efficient coal plants (Units 9 and 10, 100 MW each) in the base system. All calculations are done using the base case fuel prices. Specific details on the nature of the refurbishment changes and the replacement operating features are given in Appendix C.

Table 4-11 summarizes the results of these simulations. As usual all values are stated in $/kW terms. In this case, all results involve benefits as opposed to the constraint costs estimated above.

Table 4-11

Synergistic Effects of Refurbishment and Replacement

Case	Benefit ($/kW)
Coal Refurbishment	9
Gas Replacement	18
Coal Replacement	28
Gas Replacement + Refurbishment	70
Coal Replacement + Refurbishment	84

These results clearly show that there are substantial benefits to combining refurbishment with replacement in excess of the sum of the benefits considered separately.

We conjecture that the synergistic gain is due largely to the reduced minimum capacity involved in the refurbishment case. The refurbishment involves lowering the minimum capacity of each unit by 100 MW. The replacement resources have relatively small benefits when considered alone, because they carry implicitly the burden of their own minimum capacity plus that associated with other units, such as Coal 1 and 2. The synergistic gain, therefore, amounts to reducing that burden. This argument is made in more detail in Appendix C.

The implication of these runs is that new resources should not necessarily bear the burden of minimum load problems that are system-wide. If it is less expensive to reduce this problem by fixing existing units, then new units need not be penalized by their increment to minimum load in the absence of a system level fix.

4.4 Conclusions and Recommendations

The principal lesson which emerges from this discussion is that there can be important cost effects stemming from operating restrictions that cannot be detected by models designed for long range resource planning. A reasonable strategy to deal with these results suggests itself. A utility evaluating the price effects of bids must use a long range model with limited dispatch detail. To capture the more subtle operating effects, it is useful to model them with a detailed chronological simulation. Cost penalties calculated in the more detailed domain can then be levelized and added to the fixed cost stream of the bids with which they are associated. In this way the pragmatic value of the long range model can still be realized, and the operating restrictions appropriately valued.

It is also useful to inquire more precisely where the high minimum capacity restriction comes from in the first place. The story and the potential for remedy is different in the Doswell and the Vista/Paulsboro cases. In Doswell the problem is directly tracable to the single valued heat rate used to price variable output. As we argued extensively in Sections 1.2.4 and 1.2.5, the heat rate variation on combined cycle plants is very large. By confining the price to one heat rate, the Doswell contract creates a great risk for the seller if output is allowed to vary. The seller's solution is to restrict the output range to match the heat rate.

Clearly it would be more rational to embed the entire heat rate curve into the contract price. The 1989 Virginia Power RFP correctly moves in this direction. Bidders must offer a heat rate curve, and it appears as if payment will be tied to that curve and an indexed fuel price. The Model Contract in the RFP is not entirely clear on issues associated with linking payment to the heat rate curve, but the intention seems to be there.

The situation is different in Vista/Paulsboro. Here the high minimum capacity level stems from the interaction between the JCPL desire to limit the size of individual bids, and the bidder's attempt to capture scale economies. The Vista/Paulsboro units are each larger than the contract capacity committed to JCPL. Their capacity is 160 MW each. The minimum capacity of 80 MW therefore represents a reasonably standard level for the entire facility. It is only large relative to the contract capacity. If the bidders had configured a bid based on smaller units, they could well have had a lower minimum capacity. The cost of that would probably have been foregone construction scale economies. In this case, it seems that the JCPL size constraint on bids may have been socially inefficient.

Finally, there are other situations besides these two in which bidders might offer large minimum capacity bids. These would be cogeneration applications where steam requirements dictate substantial electricity production in all hours. These might look like the Cogen Technologies contract conditions. To make a proper evaluation of such bids, a two stage simulation strategy, as outlined above, would be appropriate.

5. RESEARCH AND DEVELOPMENT PRIORITIES

5.1 Introduction

This section summarizes the implications of the previous discussion from the perspective of research and development. Designing R&D programs requires balancing technological issues against market constraints and opportunities (Stoneman, 1987). The Clean Coal program and related coal R&D is one of the largest U.S. government programs in energy research, development and demonstration. Its concerns are multi-faceted. The work reported in this study addresses only one of the lesser facets, that is, how to account for the dispatchability of new resources when predicting industry adoption of new technologies over the relatively near future, that is, a decade or so. While dispatchability is certainly not the most important single issue, it is an easily overlooked or understated one, and, therefore, merits careful attention.

The viewpoint of this section is that of the traditional utility facing familiar and unfamiliar technologies becoming available either directly from vendors or through the competitive bidding process. We focus on competitive bidding because the evaluation loosely replicates the methods and models utilities and their regulators have long used to examine new capacity additions. The complications of arms-length contracting make the planning problem more difficult. Computer models play a central role in the planning process at electric utilities, public utility commissions, and independent power producers, and so they do in our work. The major reason for heavy reliance on computer simulation derives from the sheer complexity of the problem. It is just infeasible to account in any other way for all the details that make up dispatchability. However, the practical importance of simulation models stretches far beyond their direct role. They also frame discussion of dispatchability issues, both abstractly and concretely, because operating characteristics become key sensitive model inputs. Therefore, evaluation results are heavily influenced by the ability of current models to accommodate the various aspects that constitute dispatchability. As a consequence, it becomes difficult to separate the question of result validity from model credibility. However, with these reservations in mind, some modest implications for the direction of coal R&D can be drawn from the results presented.

5.2 Data Limitations

5.2.1 The Data Deficiency

A major difficulty immediately encountered when assessing the value of new technologies is the paucity of information on them. The information of interest in work such as this concerns the operating characteristics of new technologies. More specifically, we do not know in detail the operating characteristics that might be expected when they are out in full commercial operation under the control of entities such as the traditional electric utilities or independent power producers. That there is a data shortage may at first seem like a remarkable claim. After all, large sums of public money in many countries are spent on research into new generation technologies. This research leads to work in the public domain, and, further, vendors can be expected to advertise the capabilities of their new products. There are, however, three major limitations on the value of such sources.

First, research rarely focuses on the detailed operating capability of new resources, particularly thermal power plants. Economic analysis tends to focus on the best possible rates of energy conversion that a technology can achieve, which usually occurs at or near full capacity, and the availability and cost of fuel. This efficiency approach does provide a useful first order metric for comparison among technologies. However, assessing the value of a new resource to a utility system requires much more detailed information, and even such relatively simple operating characteristics as part-load efficiencies are rarely reported in the literature. In other words, in the language of this report, economic analysis is limited to the bus-bar cost level.

Second, the historic structure of the industry has created a highly particularized method of new capacity procurement. Large projects are usually managed by one of a select group of engineering companies. Once engaged by a utility, this company custom designs the plant to certain loose initial specifications laid out by the purchaser. Site and/or fuel constraints are often primary concerns. The engineering companies rely on individual vendors and contractors to supply the various components of the project. The operating characteristics of the proposed plant are determined iteratively along the way. The engineering company might offer several options that will change the ultimate dispatchability of the plant, and the purchaser typically makes choices one at time on the options proposed. This process makes it difficult for an outsider to assess the true range of dispatchability options available to a purchaser. There is no off-the-shelf catalog that portrays the options in a simple manner. The nearest document to such a catalog, the EPRI *Technical Assessment Guide* (TAG), reports only scanty operating details. In fact, TAG relies on classifying technologies as *BASE*, *INTERMEDIATE*, or *PEAK*, reflecting traditional industry rules of thumb about system planning. However, the utility planner can no longer rely on simple guidelines about the fractions of capacity of each type needed for a balanced system. The bidding world requires the planner to choose a basket of resources from the myriad of discreet dispatchability options offered in an auction. These are traded off against a whole range of other project attributes, which we have not considered here. This process can be very complex.

Third, the most interesting and challenging problem, from a research point of view, concerns the dispatchability of existing resources. This is best illustrated by continuing with the story told above. When the new resource becomes a turn-key project, the transfer of control from the manager of construction to the purchaser of the facility has a software component in addition to the obvious hardware component. The software consists of many things, including staff training and recommended scheduling for the new plant. Presumably, these operating instructions comply with the original specifications agreed upon by the purchaser and manager of the project. Two interesting questions surround these instructions. How, if ever, are the operating instructions altered? And, are they ever altered to meet changing economic conditions?

Let us consider the final two questions in more detail. The answer to the first question appears to be only after considerable research by plant operators, only with great trepidation, and only at great expense. For new baseload power plants there is unlikely to be a change in operating procedures. For older vintage plants, however, operating procedures will change largely due to changing economic needs. The typical case is that older facilities will be converted from baseload to intermediate or peaking service as new baseload plants come into service. This is the answer to the second question.

It is easy to see why using a plant in an optimal manner economically poses a complex problem. Evaluating the consequences of breaking the manufacturers' recommended scheduling rules not only poses tough engineering questions, but may also raise some legal problems. Costly errors resulting from not following manufacturers' recommendations raises a liability issue. Further, such events are not well received at the public utility commissions in prudence reviews. The implication of this problem at the planning level is that operating constraints tend to be incorporated into the input files of planning models and never subsequently adjusted for the purposes of evaluating the ability of the system to absorb poorly dispatchable new resources. The knowledge necessary to make such trade-offs is not readily available, nor is the existing regulatory environment one that would encourage utilities to seek it out.

Notice the dichotomy emerging between the economic operation of existing and new resources. Market forces, presumably, will encourage the independent power producer to evaluate the trade-off between greater flexibility and its related costs. It has to make its best auction bid, all aspects considered. In other words, the independent power producer can be trusted to behave in an economically rational manner. On the other hand, the traditional utility plant operator functions under the constraints outlined above and seems far more unlikely to make the optimal economic decision.

5.2.2 Research Implications

Clean Coal projects and coal R&D generally should examine operating characteristics closely associated with dispatchability such as minimum operating levels, ramp rates and so on. Results from test sites should include tests on these operating characteristics and projections for characteristics of commercial scale facilities.

A concerted effort should be made to compile the comparative data for the new technologies at the level of detail necessary for use in utility planning models, that is, somewhat beyond the level of the TAG.

The decision-making of plant operators with regard to operations of existing facilities merits investigation. Much planning begins from the assumption that all existing resources must be used as they are now. If, for example, a minimum load problem currently exists, the new additions have to mitigate it. This approach does not solve the problem in the way it should be solved, namely, how can the minimum load problem be solved at minimum cost, and the approach disfavors poorly dispatchable new technologies.

5.3 The Dispatchability Question

The basic issue with dispatchability reduces to two components, one direct and one indirect.

a. The overriding fact-of-life for electric power generation is that electricity cannot be stored at a reasonable cost. Most products can be stored at some reasonable cost, which permits an even output stream from the production process, irrespective of fluctuations in demand. Electricity, on the other hand, has to be generated as needed. Hence, the high economic benefit of technologies that can be turned on and off and up and down at will. Hence, also, the high burden of fixed cost investments, which have to be recovered from an output that must necessarily be intermittent.

b. The more subtle indirect issue concerns the ability of existing systems to absorb poorly dispatchable resources. The value of a dispatchable resource depends heavily on the pre-existing mix of resources at the disposal of the dispatcher. In other words, improvements in the dispatchability of resources in place alters the potential value of non-dispatchable new additions.

The first component says that an electric generating resource must be flexible in ways that have been described in some detail elsewhere in this study. The second component says that the value of dispatchability in a new resource addition is, in large part, a function of the flexibility of the existing stock.

5.4 Minimum Operating Capacity

5.4.1 Minimum Load Problem

The most striking finding in this work concerns minimum operating levels. It seems that reducing the size of the minimum operating level of resources offers significant benefits. This problem has been called the minimum load problem (Electrical World, March 1990). Simply stated, the problem is that for significant periods, total generation under ordinary operating procedures exceeds demand. This problem occurs because resources cannot be turned down far enough to reduce generation to the desired level. The economic problem is exacerbated because times of low load for one system parallels those of neighbors and so the opportunities for sales of the excess electricity are limited. When boilers cannot be turned off because they are needed for next day services, they are run at the lowest output level at which the unit can be safely operated. Having to run units at their minimum levels poses two problems; unwanted power is being generated. and, boilers generally do not operate efficiently at low levels of output. The inefficiency, in turn, has two components. First, for reasons of design choice and thermodynamics, plants are inherently more efficient at higher levels of output. Second, there is a phenomenon known as the *minimum load burden*. This burden raises the cost of generation at the minimum operating level above the normal heat rate of the unit.

The minimum load burden comes about for several reasons. Pre-eminent among them is the need to burn alternative fuels, usually more expensive liquid fuels, to keep boilers stable at low rates of heat flow. In utility planning, careful account cannot be taken of such minor technical effects, so an artificially high heat rate (as a proxy for high cost fuel) is simply applied to a unit when it operates at minimum load, although the fuel input is usually assumed to remain the same. Serving as it does as a proxy for complex actual effects, setting the correct size for the minimum load burden is somewhat arbitrary. Since, as this study shows, it can have a significant impact on results, the arbitrariness of the burden size is unfortunate. In California, the process of setting such planning assumptions is particularly open and the values of inputs are debated in workshops before the California Energy Commission (CEC) and the California Public Utilities Commission. The CEC actually publishes an *official* set of data input files for the large California utilities as a result of this process. In the data set for the Los Angeles Department of Water and Power, the minimum operating level heat rate for its Mojave 1 coal unit is 15617 Btu/kWh, almost double the 8181 Btu/kWh assumed for the next output level. The minimum load burden is usually higher for units that can be turned down to lower levels, but, again, the actual burden depends heavily on the design of specific units. In the case of the Mojave 1 unit, the minimum operating level is about a third of the maximum, quite low for a coal unit. That is, as planning models see it, the kWhs generated from this unit when in its minimum operating level condition cost almost double. This example is unusual for a coal plant, but it shows that the effect of the minimum operating level penalty on planning results can be significant. A high minimum operating level penalty also demonstrates the high value that a utility puts on the ability to turn down units to low levels without shutting them down completely. In fact, utilities have refurbished units for the sole purpose of reducing the minimum operating level size. Southern California Edison and Pacific Gas & Electric have both made improvements of this kind. In other words, there is evidence that the minimum load problem is severe and that this might be one of the binding constraints on utility operations (House, 1984).

5.4.2 Research Implications

From a technical standpoint, research to mitigate the minimum load problem could potentially take many routes. However, an important distinction should be made between improvements to the minimum load problem from existing resources versus improvements in the characteristics of upcoming technologies. As argued above, mitigating existing minimum load problems will make systems readily capable of absorbing inflexible new technologies.

Existing Technologies

Note first that efforts to reduce minimum operating level sizes could be worthwhile even if thea price in terms of a higher minimum load burden, especially if the fuel is relatively cheap. Not only have utilities shown their willingness to accept high burdens in the interests of lowering minimum operating level sizes, but also, additional benefits can accrue if efficient but undispatchable capacity additions can then be made. We reported an example of synergistic effects of this kind in Section 4.3.3 above.

Repowering existing coal plants with pressurized fluidized boilers (PFB) represents one of the most promising of the current Clean Coal strategies. The projects at Tidd and Vartan have shown the great potential of this approach, particularly in a world of ever more scarce sites (Pillai, 1989). The minimum load problem, however, is a potential constraint. Such repowering may contribute to the minimum load problem of a utility, and, consequently, makes it more reliant on new additions to solve the problem.

Coal micronization offers interesting benefits with regard to the minimum load problem. Advocates of micronized coal technologies claim reduced minimum load burdens can be achieved by substituting micronized coal for liquid fuels (Wiley, *et al.*, 1990). Other technologies may help reduce minimum operating levels as well.

Finally, storage technology makes power systems better able to accommodate inflexible capacity. To date, actual large scale implementation of storage has been limited to pumped storage hydro, which is, unfortunately, limited by the number of attractive sites. Other storage options such as compressed air, batteries, and magnetic storage are possible, and should be developed. Compressed air storage works in conjunction with a gas turbine and increases the power output of the turbine during release of the compressed air. This technology could be incorporated as part of a IGCC (US/OTA, 1985).

New Technologies

Turning to the more interesting issue of making the newer technologies more desirable, clearly any research that tends to reduce the minimum operating level problem must be seriously considered.

Modularization of capacity additions has numerous financial and technical advantages. Minimum load problems add another argument to the list since one obvious way to reduce the minimum operating level size is to build smaller units. In this way, shut-downs substitute for low minimum operating levels. However, modularization should be pursued only for technologies that can operate with short minimum down times and with low start-up costs. The cost in terms of shorter plant lifetime and reliability under a frequent start duty cycle also has to be considered. This is an area of great technical uncertainty.

With regard to integrated gasification combined cycles (IGCCs), integration of the gasifier and the combustion turbine is highly desirable for thermodynamic and other reasons (Makansi, 1990), in baseload operation. For intermediate load duty other possibilities should be considered. Opportunities for producing other storable fuels, such as methanol produced off-peak within integrated cycles or outside them are attractive possibilities (Eustis and Paffenberger, 1990). Given the relative inflexibility of fluidized beds, a Clean Coal strategy must rely heavily on the potential contribution to operating flexibility of the IGCCs. Thus, even if they may not seem promising, cycles with intermediate storage potential should be given a fair hearing.

Engineering folklore has maintained that fluidized bed combustion suffers from limited load following capability, since maintaining the desired combustion conditions in the bed requires an even power flow. However, there are some isolated reports of minimum operating capacities of 25% or 30%, which would be good for coal units (Moll, *et al.*, 1989; Pillai, 1989). The lack of interest in minimum load problems stems, in part, from the origin of much of this research in countries that do not have the minimum load problems the U.S. experiences. In Europe, for example, fuel flexibility poses a more serious problem than here, and, consequently, the advantages of fluidized beds are well documented. A serious research effort to resolve the likely operating constraints on fluidized beds is clearly needed. Our work suggests the minimum load problem could pose a major limitation on the adoption of fluidized bed combustion. Modularization, and/or improving start up restrictions would seem to be the best potential mitigation measures for this problem. In the AES Shady Point contract, the vendor aims to meet the tough 35% minimum load condition by constructing multiple boilers. Further, German researchers have claimed to have achieved extremely low, 12.5%, minimum operating levels by selective shut down of system modules in a PFB (Koch, *et al.*, 1989). This experience suggests that the common assumption that fluidized beds will be most useful in large sizes has to be tempered by the benefits of modularization and smaller units.

Among the other technologies, the importance of the minimum load problem implies some strong plusses for fuel cells. Not only are they modular and efficient in quite small sizes, but, unlike gas turbines, they have excellent part load efficiencies. However, start ups and shut downs may be costly (Kinoshita et al., 1988). As with gas turbines, separate gasification and fuel cells might be an attractive clean coal strategy.

5.5 Other Operating Constraints

In general, our work suggests that other operating constraints impose relatively minor costs relative to the minimum operating level problem. Marginal improvements in capabilities such as ramp rates will deliver small benefits to utilities.

5.6 Modelling Issues

5.6.1 Model Performance

In general, the models we have used in this work have performed as expected. We have not attempted to estimate the accuracy of load duration curve simulation models with more operational detail (models such as PROMOD III, for example) compared to chronological models such as BENCHMARK. It would be useful to know how much accuracy would be gained by modelling at this level compared to the long term optimization models.

Another research direction would be the exploration of unit commitment models which could shed light on operating restrictions we could not detect in BENCHMARK, such as ramp rate constraints. Such work could be very dependent on system parameters.

As a rule, the models are not capable of examining constraints on start-ups (as opposed to just charging start-up costs). Yet engineering literature (Hayes, 1990) and contract examples, such as Commonwealth Atlantic, show that constraints are real. For combustion turbines, a rule such as no more than 150 starts per year is representative.

5.6.2 Gas Turbine Enigma

The modelling and operation of gas turbines raises two issues. First, the models want to use turbines much more frequently than vendor recommendations suggest. Table 4-3 shows 200-300 starts/year for these units compared to upper limits such as 150 starts per year as specified in the Commonwealth Atlantic contract. Others have also found that the models start gas turbines too frequently (SCE, 1990). The second issue is operator behavior. It is common for operators to confine turbine use to back-up service in the event of outages, and not for ordinary economic dispatch (even subject to constraints). This phenomenon has been reported by operations planners (Jackups, 1988). The divergence between observed behavior and economics is an enigma.

The role of combustion turbines will become increasingly central during the next decade and taking optimal advantage of them is key (Williams and Larson, 1989). This year sales of gas turbines worldwide are expected to break the previous records set in the 1970s (Gas Turbine World, 1990). Gas turbines will be among the primary acquisitions of U.S. electric utilities in the coming decade. Depending on relative prices, more gas turbines may be converted from liquid fuels to natural gas. Currently, about 44% of gas turbine capacity has only liquid petroleum fuel capability, which further emphasizes the mystery of why electric utilities use their gas turbines so infrequently (USDOE/EIA, 1987). Notice that combustion turbines are one of the most flexible of resources. They are not known for high efficiency at low power levels, but they can be manufactured in a wide range of sizes (roughly 30 - 150 MW) with similar heat rates. Large numbers of small combustion turbines are a highly dispatchable resource, and their existence in the resource mix makes the absorption of large baseload additions considerably more palatable. Further, adding gas turbines may be one of the few options utility engineers will be free to choose without adopting a bidding procedure. For these reasons, gas turbines are looking like an increasingly attractive resource for traditional utilities. Therefore, not only should they be used appropriately by operators, but their treatment in models should be improved.

5.6.3 Research Priorities

The finding that most operating constraints do not significantly affect costs for our test utility may well not withstand close scrutiny. It could be that the modelling instruments available to us are too blunt to capture the effects of these constraints. In fact, we suspect this may be the case. Using hourly data and specifying all constraints in terms of hours comes from a long U.S. modelling tradition, but it may no longer provide the detail needed to evaluate real-time concerns. In other countries, 30 minutes has become the standard interval.

The gas turbine enigma raises the question of whether discrepancy between modelling results and practice implies that models are inaccurate, or that scheduling practice is uneconomic. This issue needs resolution, and should be considered a modelling priority. Likely avenues for research are the following.

a. It is quite likely that key considerations regarding gas turbines are not being correctly or adequately treated by current models. One such consideration is the cost of gas turbine refurbishment. The life expectancy of a turbine before refurbishment is largely determined by the number of starts it endures (Christian, 1978). Standard treatment of start up costs in production cost models does not account for this adequately.

b. If the models are correct in their proposed scheduling of combustion turbines, then the opposite question arises, why do system operators seem to behave otherwise.

5.7 Conclusion

The most notable result of this work concerns the minimum load problem. Research to understand and mitigate this problem has emerged as the clear pressing need. The problem has several aspects concerning existing plant, new additions, and modelling problems. All are worthy of further work.

The gas turbine dilemma also poses some important issues for further work, as does the more mundane problem of assembling better operating characteristics data.

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Appendix A
Evaluation of Ratio Scoring

In order to analyze ratio scoring we must model both a utility and the bids that it would evaluate in an auction. In the following sections we first lay out a general framework, including definitions of all the important variables, we then use the framework to prove three general results about bid scoring. Finally, we give a detailed account of the example presented in Section 2.

A.1. Definitions and Approximations

An auction must provide a certain amount of new capacity, not a certain amount of new energy. Once the new capacity is purchased, the needed additional energy may come from the new or old capacity, or the new capacity may even supply more energy than needed by replacing some more expensive energy from old capacity. To analyze these possibilities we introduce the standard load duration curve.

The utility's post-auction needs are best described by a new load duration curve, $L(T)$, where T is duration. The new needs implied by this curve could be met in several ways without resorting to an auction; and among these ways one will be found that is least cost. The avoided cost of bids will be defined relative to this least-cost, non-auction alternative. For the sake of concreteness we will assume this least-cost alternative is the purchase of peaking technology (gas turbines). If this were not the case, nothing in the following argument would change, but the name of the least-cost technology.

From $L(T)$, we can compute the *utility's total cost*, TC_{peak}, of meeting the new demand with peaking technology. Now for any particular bid with capacity K, we can compute the total cost of $L(T)$ with the bid replacing K units of peaking technology; call this TC_{bid}. We can at the same time compute how much of this cost would be owed to the bidder; call this cost C.

From these calculated quantities we can define two others. Differential cost is $DC = TC_{peak} - TC_{bid}$. Avoided cost is the cost (not counting the cost of the bid itself) that is avoided by accepting the bid in place of equivalent peaking capacity; so it is just DC plus the cost of the bid, C. Thus avoided cost is $AC = C + DC$. This is equivalent to $DC = AC - C$, also a useful formula, which may seem more familiar to readers who are used to beginning the discussion with a definition of avoided cost.

We can now define our first set of variables, the annualized cost variables. These measure costs per calendar year and are not normalized for the size of the project. Each variable comes in three versions. The fixed cost version pertains to annualized capital costs, while the variable cost version pertains to annualized energy costs, taking into account the capacity factor. The sum of these two is the total cost which is simply referred to as the cost.

For our purposes it will be more useful to work with costs that have been normalized to the bid capacity. These are found simply by dividing each of the variables defined in Table A-1 by the capacity of the bid. For example, $ac = AC / K$ where K is the capacity of the bid. We denote the normalized variables by lower-case versions of the Table A-1 variables.

We have just defined the avoided cost of the first bid accepted, but as each bid is accepted it changes the utility's cost structure a little, and this changes the avoided cost of the remaining bids. But for an auction that is small compared with the utility's total load, calculations of

Table A-1.			
Definitions of Annual Cost Variables (variables apply to a single bid)			
	fixed	variable	total
Avoided Cost	FAC	VAC	AC
Cost	FC	VC	C
Differential Cost	FDC	DVC	DC

Table A-2.			
Definitions of Normalized Annual Cost Variables ($ per kilowatt capacity)			
	fixed	variable	total
Avoided Cost	fac	vac	ac
Cost	fc	vc	c
Differential Cost	dfc	vdc	dc

TC_{bid}, DC, *and*, AC will change very little as accepted bids replace the utilities least-cost peaking capacity. As our first approximation we will assume that there would be no difference at all. In other words we assume that a bid has the same differential cost and same avoided cost whether it is the first bid accepted or the last.

A.2. Why the Difference Score is the Correct Approach

The logic of the difference score is really quite straightforward. The point of an auction is to purchase a certain amount of generating capacity, and in doing so to save the utility as much money as possible relative to what would have been spent had the auction not been held. To accomplish this the utility should make sure that it saves as much as possible on each unit of capacity purchased. That savings should of course be measured in dollars and not merely as a percentage. Per capacity differential cost (dc) is defined to measure this savings and consequently is by definition the correct measure on which to base a scoring system.

The fact that the differential cost is the correct basis tells us nothing about the direction or magnitude of the biases inherent in using the ratio score. In fact it does not even imply the ratio score is wrong until we demonstrate that it would, in some circumstances, select different bids. These differences do exist and the following section makes a complete analysis of them.

A.3. Three General Results on the Bias of Ratio Scoring

Although Jersey Central Power and Light (JCPL) defines the critical ratio as C / AC, this is clearly equivalent to c / ac. Generally we will use the second definition based on normalized annual costs because in this form it is most comparable to our definition of the difference score dc, which equals $ac - c$. By factoring out ac, the difference score becomes $ac \cdot (1 - c / ac)$. Now it is clear that the term in parenthesis has a simple one-to-one relationship with the cost ratio. This means that two bids that are equivalent under the ratio rule will not be equivalent under the difference rule if they differ in per-capacity avoided cost. Since such differences are to be expected, the two rules cannot be equivalent. We now begin our analysis of how they differ.

A.3.1. The First Result

Consider two bids with the same ratio score; that is:

$$\frac{c_1}{ac_1} = \frac{c_2}{ac_2}$$

Two bids with the same ratio score are likely not to have the same difference score, so let us call the one with the greater difference score bid 1. We now investigate what it is that will cause this greater difference score when the ratio scores are equal.

$$dc_1 > dc_2$$

holds if and only if

$$ac_1 - c1 > ac_2 - c_2,$$

which holds if and only if

$$ac_1 \cdot (1 - \frac{c_1}{ac_1}) > ac_2 \cdot (1 - \frac{c_2}{ac_2}).$$

Now assuming that the the ratio score is less than one, so that the term in parenthesis is positive, we see that because the ratio scores are the same, the last equation is true if and only if

$$ac_1 > ac_2,$$

which is equivalent to

$$c_1 > c_2.$$

This proves our first result.

RESULT 1:
If two bids have the same ratio score and it is less than 1, then the bid that costs more per unit of capacity will have the greater differential cost and is to be preferred.

Remember that the higher cost is mostly associated with a greater capacity factor and thus with greater use. Since savings is proportional to use, result 1 is not counter intuitive.

Now while this result is perfectly general, it does not quite close the discussion. It is not obvious that higher cost is *always* associated with a lower energy price, so we will now make a deeper analysis of this question.

A.3.2. Calculating Differential and Avoided Costs.

In order to compare more precisely the outcome of the two bid-selection algorithms, we will need to describe the capital structure and load duration curve of a typical utility and the derive differential and avoided costs. We now proceed to define the method of computing these costs.

We will discuss both capital structure and the load duration as if they could be described by continuous functions. This will greatly simplify some of the transformations and approximations that we need to make. In the end we will find that there has been no loss of generality, because some advanced calculus techniques will allow us to differentiate step functions, so all of our results can be converted back to discrete formulas, whenever that is necessary.

Costs can be divided between energy and capacity charges. The analysis of energy costs is complicated by the fact that dispatch is done on the basis of the energy cost. We analyze the energy costs first, and the matter of capacity charges will be handled easily at the end.

The utility's anticipated demand for energy will be described by a standard load duration curve, $L(T)$, where T is duration, and $0 \leq T \leq 1$. Load is measured in kW. Capacity is described by a standard marginal cost of supply curve, V(L), where V stands for variable cost and is measured in \$/kWyr. The construction of this curve naturally assumes the cheapest power is dispatched first.

The area under the load duration curve can be divided into horizontal bands representing energy generated by plants with different energy-costs. The area of each band gives the total energy supplied by its associated plant. Because of this, total energy (variable) cost can be computed as follows:

$$TVC_{peak} = \int_0^{\bar{L}} V(L) \cdot T(L)\, dL,$$

where $\bar{L}$ is the maximum load, "peak" indicates that the utility has used its default (no-bids-accepted) expansion plan, and $T(L)$ is the inverse load duration curve, and is defined by $T(L(T)) = T$. For the moment we will find $T(L)$ more convenient than $L(T)$, because it shares with V(L), the independent variable L.

We need to compute the new total cost after a bid is accepted. An accepted bid, of capacity K, will be added to the load duration curve at some point L^*, which is determined by its energy cost. This will have no affect on the V(L) for $L < L^*$, but will shift V(L) to the right, by an amount K, for all points to the right of L^*. Thus for $L > L^* + K$, the new variable cost function is $V_{bid}(L) = V(L-K)$. For the region between L^* and $L^* + K$, $V_{bid}(L) \doteq V_{bid}$, where V_{bid} is the energy price of the bid. Because, we are assuming the bid is small, and because $V_{bid} = V(L^*)$, we can make the approximation that $V_{bid}(L) = V(L-K)$, for the region between L^* and $L^* + K$, as well. This approximation is exact at the right end of the region.

We are now prepared to compute TVC_{bid} and DVC.

$$TVC_{bid} = \int_0^{L^*} V(L) \cdot T(L)\, dL + \int_{L^*}^{\bar{L}} V(L-K) \cdot T(L)\, dL.$$

Since differential variable cost, DVC, equals $TVC_{peak} - TVC_{bid}$,

$$DVC = \int_{L^*}^{\bar{L}} [V(L) - V(L-K)] \cdot T(L)\, dL.$$

If we now factor a K out of the term in brackets it becomes $[V(L) - V(L-K)]/K$, which is equal to dV/dK at some point between L and $L-K$. Since K is, by assumption, small, we simply approximate $[V(L) - V(L-K)]/K$ by $V'(L)$. This yields a simpler formula for differential cost:

$$DVC = K \cdot \int_{L^*}^{\bar{L}} V'(L) \cdot T(L)\, dL.$$

The per-capacity differential cost is just:

$$vdc(L^*) = \int_{L^*}^{\bar{L}} V'(L) \cdot T(L)\, dL. \qquad \text{(A-1)}$$

We now have a way of computing *vdc* which is the correct measure of variable cost to use in evaluating bids, but we also want *avc*, the variable cost component of avoided cost. This is found by adding the per-capacity variable (energy) cost of the bid to *vdc*. The energy cost of the bid is $C = K \cdot V_{bid} \cdot T(L^*)$, where $T(L^*)$, also called T^*, is the duration implied by the bids position in the loading order. The bid's energy cost is simply $c = V_{bid} \cdot T^*$.

As it turns out, a small simplification in our result can be achieved by a change of variables. Instead of viewing V as a function of L, we can view it as a function of T by making the following obvious definition.

$$V(T) = V(L(T)),$$

where $L(T)$ and $V(L)$, were both previously defined. In order to effect this change of variables we need to replace dL with an expression involving dT; this is derived from the definition: $dL/dT = L'(T)$. We also note that the integration limits, L^* and $\bar{L}$, must be replaced by T^* such that $L^* = L(T^*)$ and 0 because $\bar{L} = L(0)$. These substitutions allow us to re-write our formula as follows:

$$vdc(T^*) = \int_{T^*}^{0} V'(L(T)) \cdot T(L(T)) \cdot L'(T)\, dT.$$

A simplification is achieved as follows:

$$\frac{dV(L(T))}{dT} = \frac{dV}{dL} \cdot \frac{dL}{dT} = V'(L) \cdot L'(T)$$

which implies

$$V'(L) = V'(T)/L'(T).$$

Substituting into the last version of our formula and reversing the limits of integration we have:

$$vdc(T^*) = -\int_{0}^{T^*} V'(T) \cdot T\, dT. \qquad \text{(A-2)}$$

A.3.3. Second Result

We now have the tools necessary for proving our second result. Our first result was stated in terms of the cost of a bid. Since this depends on capital cost, energy cost and capacity factor, we would like to have a result that is more specific, and if possible stated in terms of a characteristic of the bid. Result two accomplishes this.

We know that lower energy price is monotonically associated with greater duration, so we are free to analyze the problem in terms of a bid's duration. Our first step is then to describe a family of bids having the same ratio scores, but differing in duration. Since avoided cost (ac) equals differential plus cost ($dc + c$), such a family is described by

$$s = \frac{c}{dc + c},$$

where s is the ratio score, and

$$c = fc + vc \quad \text{and} \quad dc = \overline{fc} - fc + vdc.$$

Here, fc and $\overline{fc}$ are fixed cost per unit capacity of the bid and of the avoided peaking capacity, vc is variable cost, and the prefix d indicates one of the per-capacity differential cost variables. We have used the fact that differential cost, dc, is simply the sum of differential variable and differential fixed costs, and that differential fixed cost is just peaking fixed cost minus the bid's fixed cost. Substituting into the score equation and rearranging we have

$$s \cdot (\overline{fc} + vdc + vc) = fc + vc.$$

Since the bid's variable cost is determined by its duration, we are only free to choose its fixed cost. Therefore we solve for fixed cost.

$$fc = s \cdot (\overline{fc} + vdc + vc) - vc$$

Any bid that satisfies the above equation will have a ratio score of s, but what can be said of its differential cost?

$$dfc = \overline{fc} - s \cdot (\overline{fc} + vdc + vc) + vc$$

So,

$$dc = \overline{fc} - s \cdot (\overline{fc} + vdc + vc) + vc + vdc.$$

Which simplifies to

$$dc = (1 - s) \cdot (\overline{fc} + vc + vdc)$$

Now replace vc with $T \cdot V(T)$, and vdc with the our second formula, equation (A-A-2), the one that uses functions of duration.

$$dc = (1 - s) \cdot [\, \overline{fc} + T \cdot V(T) - \int_0^{T^*} V'(t) \cdot t \, dt \,]$$

We would now like to find how the differential cost, dc, varies with duration, T. In other words we wish to find the derivative of dc with respect to duration.

$$\frac{d\,dc}{dT} = (1 - s) \cdot [\, V(T) + T \cdot V'(T) - \frac{d}{dT} \int_0^{T} V'(t) \cdot t \, dt \,]$$

This looks a bit messy, but the fundamental theorem of calculus assures us that differentiation is the inverse of integration, so the last term just reduces to the function being integrated.

$$\frac{d\,dc}{dT} = (1 - s) \cdot [\, V(T) + T \cdot V'(T) - V'(T) \cdot T \,]$$

And this, of course, simplifies to our second result, namely

$$\frac{d\,dc}{dT} = (1 - s) \cdot V(T). \tag{A-3}$$

This result can be interpreted as follows:

RESULT 2:

If a family of bids has the same ratio score, and it is less than 1, then bids with lower energy prices, and thus higher duration, will have higher differential costs and will thus be preferred.

This statement of the result has the appearance of depending on the existence of a family of bids, but this is deceptive. If we consider any two bids with the same ratio score that is less than 1, it will be possible to construct a family of bids connecting the two and described by a differentiable energy price function. We have already shown how to construct a fixed cost that will insure that the family has a constant ratio score. When result 2 is applied to this family it allows us to conclude:

RESULT 2*:

If two bids have the same ratio score and it is less than 1, then the one with the lower energy price will have the higher differential cost and is to be preferred.

This result does not depend on the shape of the load duration curve, or on the variable costs of the utility's capacity; it depends only on the energy price of the two bids being positive.

A.3.4. Third Result

We now know exactly which bids will be discriminated against by the ratio scoring method, but we would also like to know by how much. We can ask how much more a base-load bid is worth than a peaking bid with the *same* ratio score. (We will call this the Lost Value, LV, of the base-load bid of ratio score s.) Consider two bids with the same score, the first scheduled to operate at duration T_1, and the second at the greater duration T_2. The lost value of accepting the short duration bid is just $dc(T_2) - dc(T_1)$. Now a rather complicated way to view this difference is to think of it as the integral of the derivative of $dc(T)$ from T_1 to T_2. By viewing it this way we can apply equation (A-3) to find:

$$LV(sc, T_1, T_2) = \int_{T_1}^{T_2} (1 - sc) \cdot V(T)\, dT.$$

Or,

$$LV(sc, T_1, T_2) = (1 - sc) \cdot (T_2 - T_1) \cdot V,$$

where

$$V = \int_{T_1}^{T_2} V(T)\, dT.$$

Note that V is simply the average energy cost for the utility's generating capacity that is dispatched with duration between T_1 and T_2. If V is measured in mills/kWh, then duration should be measured in hours and LV will be measured in dollars per kW of capacity.

One way of interpreting this expression, is to note that in a correctly scored auction, a base-load plant could increase its bid by $(1 - sc) \cdot (T_2 - T_1) \cdot V$ relative to its bid in a ratio-score auction, without loosing any ground against peak-load bids. If the accepted bids in an auction

RESULT 3:

The value lost by accepting a low-duration (T_1) bid with ratio score sc, in place of a high-duration (T_2) bid with the same ratio score, is $(1 - sc) \cdot (T_2 - T_1) \cdot V$ per kW of capacity, where V is the utility's average energy price for generating capacity with durations in the range T_1 to T_2.

have ratio-score noticeably below 1, LV will represent a significant sum.

A.4. Analysis of the Example

In Section 2 we described the results of an example of the two bidding systems as they would be applied to hypothetical bids by a hypothetical utility. There we claimed that both the fictitious utility and fictitious bids were fairly realistic representations of what is to be found in the market. Here we will present the details of both so the reader may judge these claims of realism, and we will present a description of the calculations sufficient to reproduce them.

The example begins with a description of the utility's load duration curve and its energy price curve. These are shown in Figures A-1 and A-2, and the numeric values for these curves are shown in Table A-3. The first stage of the calculation uses the equation (A-1) to find vdc, which is also reported in Table A-3. Because load energy cost is measured in mills/kWhr, equation (A-1) must be modified to read as follows.

$$vdc(L^*) = \frac{8766\ hrs}{1\ year} \frac{1\ \$}{1000\ mills} \cdot \int_{L^*}^{\bar{L}} V'(L) \cdot T(L)\, dL. \qquad \text{(A-4)}$$

This will give us vdc in \$/kW. From differential variable cost, vdc, we can begin our computation of the two key variables used by JCPL in their scoring system. They use what we have called avoided price, which is measure in mills/kWh (instead of mills/kW), and what we will call "differential price", also measured in mills/kWh. The variable component of differential price, dvp, is found simply by correcting vdc for duration and changing units.

$$dvp = \frac{1}{8.766} \frac{vdc}{T}$$

Since dvp is just defined as $avp - vp$, where avp is avoided variable price and vp is energy price in mills/kWh, we have

$$avp = vp + dvp.$$

The values for these variables, along with the assumed values for load (L), duration (T), and variable price (vp) are given in Table A-3.

Table A-4 is a replica of Table 2-2, which is included here for convenience with the variable names now accompanied by their corresponding symbols. Also included, on the first two lines is duration of each bid. We will now give sources for all of these variables.

T = assumed value.

vp = assumed value.

$vc = 8.766 \cdot vp \cdot T.$

fc = assumed value.

$$c = vc + fc.$$

$$avc = vc + vdc.$$

$$afc = \text{assumed value.}$$

$$ac = avc + afc.$$

$$vdc = \text{value given by equation (4)}.$$

$$dfc = afc - fc.$$

$$dc = vdc + dfc.$$

The JCPL scoring system uses lookup tables that essentially embody the variable price and avoided variable price that are computed above. These curves are plotted in Figure A-3.

Figure A-1. Load Duration Curve

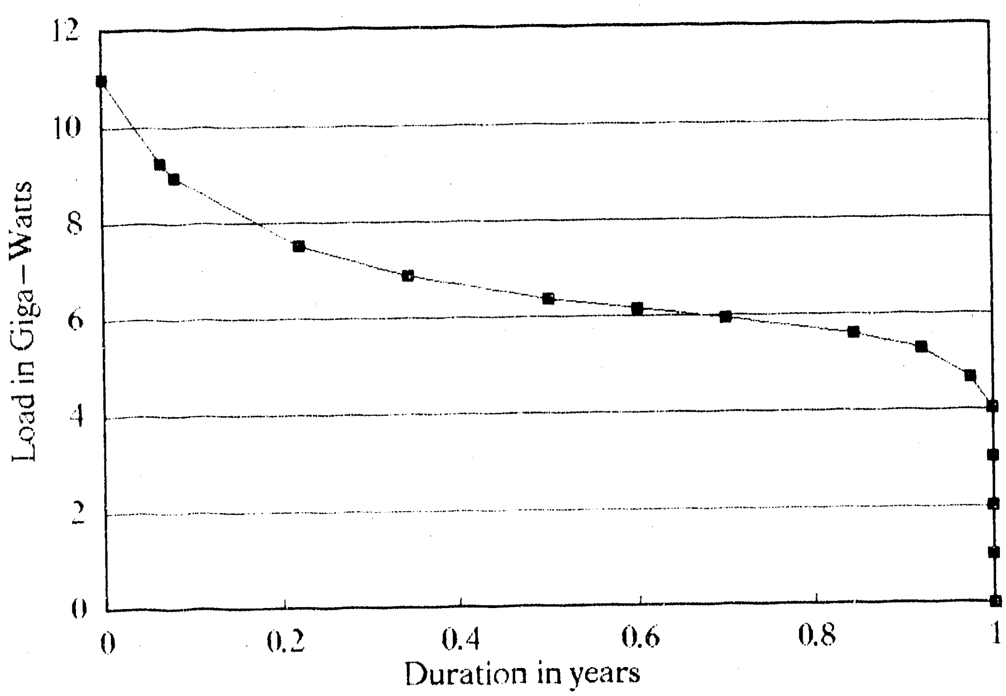


Figure A-2. Energy Price Curve

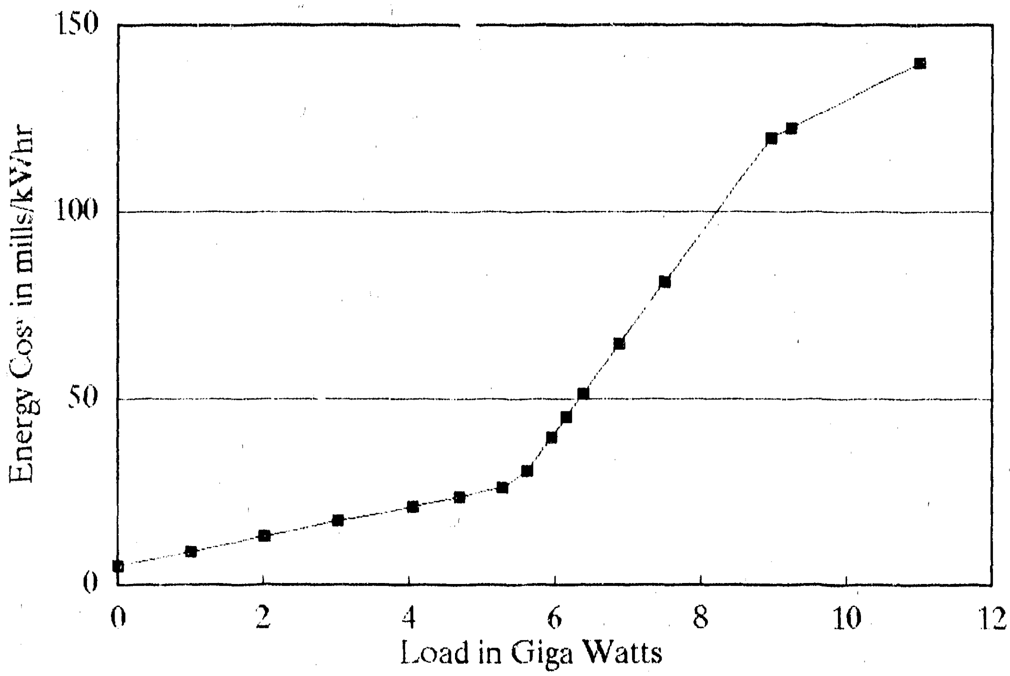
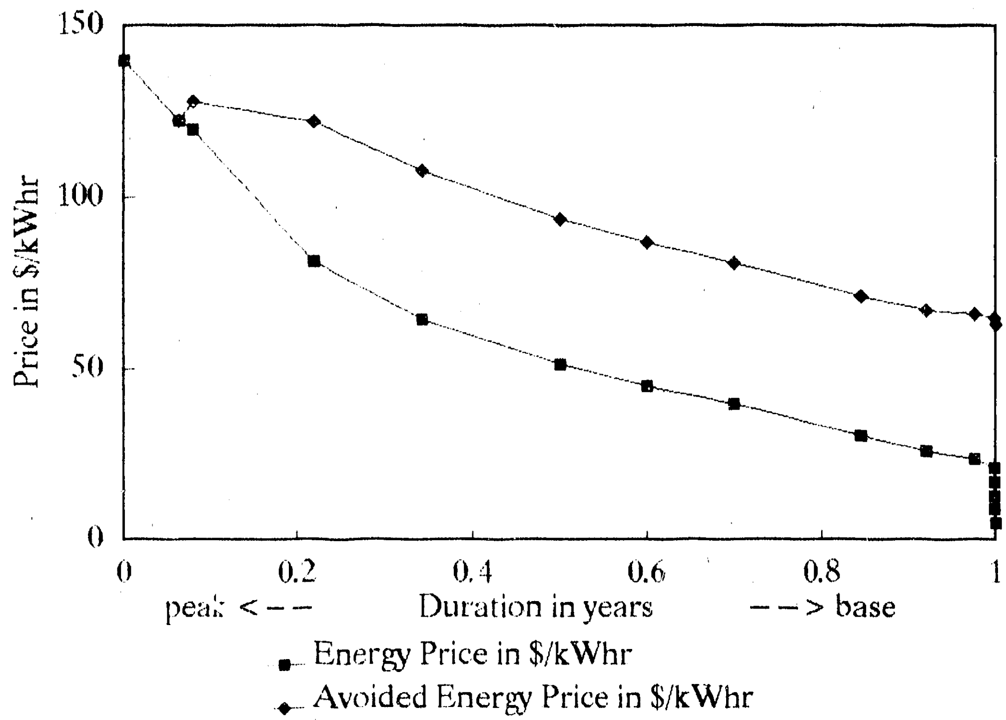


Table A-3.						
Bid	L	T	vp	vdc	dvp	avp
	0.00	1.00	5.0	506.8	58	63
	1.01	1.00	9	489.2	56	65
	2.02	1.00	13	453.9	52	65
	3.03	1.00	17	418.7	48	65
	4.04	1.00	21	383.5	44	65
	4.68	0.975	24	361.2	42	66
	5.28	0.92	26	330.5	41	67
base	5.61	0.844	30.5	301.8	41	71
	5.95	0.70	40	253.1	41	81
	6.16	0.60	45	218.8	42	87
	6.39	0.50	51	186.3	43	94
intermediate	6.88	0.342	64.6	129.8	43	108
	7.51	0.22	81	78.6	41	122
peak	8.95	0.080	119.7	5.8	8	128
	9.24	0.06	123	0.0	0	123
	11.00	0.00	140	-13.8	0	---

Table A-4. Example Outputs for Three Representative Bids				
		Base-Load	Intermediate	Peaking
duration in hours		7400	3000	700
duration	T	84%	34%	8%
variable energy price	vp	30.5	64.6	119.7
variable energy cost	vc	226	194	84
annual fixed cost	fc	315	160	57
annual total cost	c	541	354	140
avoided variable cost	avc	527	324	90
avoided fixed cost	afc	64	64	64
avoided total cost	ac	591	388	154
differential variable cost	vdc	302	130	6
differential fixed cost	dfc	-251	-96	8
differential total cost	dc	51	34	13
cost/(avoided cost)	c/ac	0.91	0.91	0.91

Figure A-3. JCPL Type Curves for Price and Avoided Price



Appendix B
Calculation of the Rental Cost of Capital

This appendix supports Section 3 by deriving results that are discussed but not derived in that section. We begin by with a list of continuous-time variables and their definitions.

Table A-1: Continuous-Time Variable Definitions	
RR	Rental Rate. Rent is paid continuously at $RR per year.
C_0	Value of new plant at time 0.
$C(t)$	Value of new plant at time t.
$c(t)$	Value of plant age t at time t.
L	Life of plant in years.
ρ	Real annual continuously compounded interest rate.
r	Real annual discrete interest rate. $1 + r = e^{\rho}$

A.1. Derivation of Capital Value from the Present Value of Net Income

Here we derive the value of capital as a function of time from the assumption that its value is equal at every time to the present value of the net income stream that it will provide during the remainder of its lifetime. To this end let y equal net revenue, $c(t)$ be the value of the t-year-old capital at time t, and ρ be the continuous interest rate. We can then write:

$$c(t) = \int_0^{L-t} y \cdot e^{-\rho\tau} d\tau . \tag{A-1}$$

Now this equation must hold a time 0, and at that time the value of the capital is represented by C. This gives us the equation

$$C = \int_0^{L} y \cdot e^{-\rho\tau} d\tau. \tag{A-2}$$

These two integrations can be performed to find

$$c(t) = \frac{y}{\rho} \cdot \left[1 - e^{-\rho \cdot (L-t)}\right], \tag{A-3}$$

and

$$C = \frac{y}{\rho} \cdot \left[1 - e^{-\rho \cdot L}\right]. \tag{A-4}$$

Now solve for y in equation (A-4) and substitute this expression for y in equation (A-3) to find

$$c(t) = \frac{C \cdot \left[1 - e^{-\rho \cdot (L-t)}\right]}{1 - e^{-\rho \cdot L}} . \tag{A-5}$$

In order to facilitate comparison with the analogous result in Section 3, we must convert to discrete-time notation. To do this, simply note that at the end of one year of continuously compounded interest at rate ρ, a unit of value will have increased to e^{ρ} units of value. Thus

$$1 + r = e^{\rho} \tag{B-6}$$

where r is the annual interest rate as it is in Section 3. Using this relationship to substitute for ρ in equation (B-5) we find

$$c(t) = \frac{C \cdot \left[1 - (1 + r)^{t-L}\right]}{1 - (1 + r)^{-L}}.$$

This can be seen to be the same formula for $c(t)$ as was derived by the "resale" approach in Section 3, equation (3-4).

B.2. Derivation of Rent from Capital Value, C(t)

Rent must cover interest payments on the value of the capital and depreciation of the capital. Denoting the continuous rental rate by RR we can write this relationship as:

$$RR = \rho \cdot c(t) - \dot{c}(t), \tag{B-7}$$

where $\dot{c}(t)$ is the time derivative of capital value and is negative because it depreciates. Evaluating the derivative and carrying out the subtraction we have:

$$\frac{RR}{C} = \frac{\rho}{1 - e^{-\rho L}}. \tag{B-8}$$

On the left we have rent per unit capital. We again wish to convert this to a discrete time formula for the sake of comparison, so we will need equation (B-6) and a new one that relates the continuous rental rate RR to a discrete rent paid at the start of the year, R_0. That formula is derived from the fact that the present value of one year of continuous rent should be equal to the annual (paid in advance) discrete rent; in other words:

$$R_0 = \int_0^1 RR \cdot e^{-\rho \cdot \tau} d\tau.$$

This relationship simplifies to the one we will use, which is

$$R_0 = RR \cdot (1 - e^{-\rho}) / \rho. \tag{B-9}$$

Using equations (B-6) and (B-8) to substitute for ρ, and RR, in equation (B-9) we find that discrete-time rent,

$$\frac{R_0}{C} = \left[1 - \frac{1}{1+r}\right]\left[1 - (1+r)^{-L}\right]^{-1}. \tag{B-10}$$

This will be of interest for the sake of comparison after we derive the comparable formula taking into account inflation and technical progress. We now define R to be rent paid at the end of the year in anticipation of the next subsection, and note that $R = R_0 \cdot (1+r)$. This allows us to adjust the formula to represent rent paid at the end of the year.

$$\frac{R}{C} = r \cdot \left[1 - (1 + r)^{-L}\right]^{-1}.$$

This is exactly the equation (3-5).

B.3. Derivation of Rent with Inflation and Progress

In this subsection we will derive the formula, given in Section 3, for rent in a world with inflation and technical progress. We will do this computation in discrete time as a way of checking our continuous time calculations and because discrete time is a very popular technique. This will allow us to avoid calculus but will require far more care with our definitions. In particular, we will first define rent, R, as being paid at the end of the year. We do this because it is probably the most standard practice. Unfortunately this will make it appear that real rent depends on the inflation rate. To show that this is not the case we also convert the formula to a pay-first definition of rent.

We begin by defining our variables.

Table B-2: Discrete-Time Variable Definitions	
$R(t, a)$	Rent for year t on a plant of age a at start of year t. Rent to be paid at end of each year.
$R(t)$	Rent for year t (paid at year end) on a plant of any age.
C_0	Value of new plant at *beginning* of year 1.
$C(t)$	Value of new plant at *beginning* of year t.
$c(a)$	Value of plant age a at *beginning* of year 0.
$c(t, a)$	Value of plant age a at *beginning* of year t.
L	Life of plant in years.
i	Annual inflation rate.
g	Annual rate of price decrease due to technological progress.
z	Annual rate of price change due to inflation and technological progress. $(1+z) = (1+i)/(1+g)$.
nr	Nominal annual interest rate.
r	Real annual interest rate. $1+r = (1+nr)/(1+i)$.

Our first step is to recognize that the price of a new plant, C_0, must equal the price of a used one, plus the cost of replacing it when it dies, minus the value of the replacement plant L years after the start of this process. With either the new- or the used-plant scenario the functionality for the owned plants is the same; the owner has a fully functioning plant for L years. Thus the two scenarios must have equal present-value cost. We express this as

$$C_0 = c(a) + (1+nr)^{a-L} \cdot C_0 \cdot (1+z)^{L-a} - (1+nr)^{-L} \cdot c(a) \cdot (1+z)^L \qquad \text{(B-11)}$$

Note that by definition of z, the cost of new capital must change by $(1+z)^{L-a}$ after $L-a$ years. Since the price of used capital depends only on the current and future price of new capital, and is proportional to it, the price of used capital of a given age must also change by $(1+z)$ per year. This explains the origin of the factor $(1 + z)^L$ at the end of equation (B-11).

The next step is to solve for $c(a)$, the value of a plant of age a at time zero.

$$c(a) = C_0 \cdot \left[1 - \left[\frac{1+z}{1+n}\right]^{L-a}\right] \cdot \left[1 - \left[\frac{1+z}{1+n}\right]^{L}\right]^{-1} \tag{B-12}$$

We next note that the price of used capital increases at the annual rate of 1+z as explained above, so we have

$$c(t, a) = c(a) \cdot (1+z)^{t-1} \tag{B-13}$$

The -1 is needed because $c(1, a)$ refers to the price at the beginning of year 1 ($t = 1$), which is exactly $c(a)$.

We now turn to the question of rent. $R(t, a)$ is the rent due at the end of year t for equipment that was age a at the beginning of year t. That rent will equal the value of the plant at the beginning of the year times $(1+nr)$, to account for interest, minus the value of the plant at the end of the year. Symbolically we have:

$$R(t, a) = (1 + nr) \cdot c(t, a) - c(t+1, a+1). \tag{B-14}$$

Substituting for $c(a)$ in equation (B-13) from equation (B-12), and for $c(.,.)$ in (B-14) from (B-13) we have

$$R(t, \frac{a)}{C_0} = \frac{(1+nr) \cdot \left[1 - \left[\frac{1+z}{1+nr}\right]^{L-a}\right] - (1+z) \cdot \left[1 - \left[\frac{1+z}{1+nr}\right]^{L-a-1}\right]}{1 - \left[\frac{1+z}{1+nr}\right]^{L}} \cdot (1+z)^{t-1} \tag{B-15}$$

This simplifies to

$$\frac{R(t)}{C_0} = R(t, \frac{a)}{C_0} = (nr - z) \cdot \left[1 - \left[\frac{1+z}{1+nr}\right]^{L}\right]^{-1} \cdot (1 + z)^{t-1} \tag{B-16}$$

Note that rent is independent of the plant's age. Equation (B-16) is analagous to the standard formula for rent but with technical progress included. This equation will become easier to interpret if we redefine rent as being paid at the beginning of the year; we call this rent R_0. Clearly $R_0 \cdot (1+nr) = R$, and we use this fact, along with the definition of real interest given in table (B-1), to re-write equation (B-16) as

$$\frac{R_0(t)}{C_0} = \left[1 - \frac{1}{(1+r)(1+g)}\right] \cdot \left[1 - [(1+r)(1+g)]^{-L}\right]^{-1} \cdot (1 + z)^{t-1} \tag{B-17}$$

We can now see clearly that the initial rent does not depend on the inflation rate once the real interest rate is known. Inflations only influence is on future rent payments which are affected in the standard way. It is also worth checking the formula for the special case where $L = 1$. In this case, the one time rent payment becomes C_0, just as it should, independent of the real rate of interest.

But the most interesting implication of equation (B-17) is that the rate of technical progress plays the same role as the real interest rate. In fact we could have derived equation (B-17) from (B-10) just by replacing $(1+r)$ with $(1+r)(1+g)$. The means that expected future technical progress causes an increase in current rent. Of course actual future progress will bring rent down at the rate of progress. This logic behind the higher rent is simple. Technical progress causes the value of existing capital to decline as it becomes possible to replace it more cheaply. In other words technical progress causes depreciation of existing capital. This depreciation, just like the normal kind, must get factored into rent.

For the sake of completeness, and because it is more succinct, we now give the continuous-time version of equation (B-17).

$$\frac{RR(t)}{C_0} = \frac{\rho + \gamma}{1 - e^{-(\rho + \gamma)L}} \, e^{(\iota - gm)t} \, , \tag{B-18}$$

where $RR(t)$ is the continuous rental rate, and where $e^{\gamma} = 1 + g$, and $e^{\iota} = 1 + i$, just as $e^{\rho} = 1 + r$.

APPENDIX C
Modelling Technical Notes

C.1 Introduction

As mentioned in the main text, the work reported here on the valuation of dispatchability reported in Section 4 was mostly done with a standard industry chronological production cost model, BENCHMARK. Certain long term results were calculated using the optimization model, EGEAS, and some comparisons of results between the two models were also conducted.

This appendix will focus on the technical problems encountered with BENCHMARK, and prov'de a little more insight into what drives the results of Section 4.

BENCHMARK is one of a group of models often known as *Monte Carlo Chronological*, or simply *chronological* models. Not surprisingly, this name distinguishes them from the non-chronological, that is, load duration curve (LDC) models. A lengthy explanation of this distinction, which goes far beyond Table 4-1, can be found in Marnay and Strauss, 1989. The two key distinguishing characteristics to note about Monte Carlo Chronological models are the following:

a. The randomness of resource failures is taken account of by Monte Carlo sampling. This simply means that the system state, that is, the roster of available resources, is established by random drawings. The rules of independence of classical statistics are assumed to hold. Expected results are simple averages over a large number of random draws, making this process computationally demanding. As a result, BENCHARK is designed to simulate test periods of no longer than a year.

b. The unit commitment and dispatch progresses hour by hour, using various rules of thumb to take account of dispatc' .bility of resources. This approach closely replicates how a real world dispatcher might cope with the given system state.

The strengths of Monte Carlo models are threefold:

a. They rely on simple statistical methods and basic heuristics that require relatively little technical knowledge to understand. Comprehensibility is particularly important in planning applications in which all results are litigated both before utility commissions and in the courts.

b. They retain the full chronological information contained in load and other input data. Without this information, proper account can never be taken of real-time limitations on dispatchability.

c. Their outputs include full hourly detail of system operations. This detailed output is invaluable to modelers trying to track down the source of aggregate results, or to understand the hourly operations implications of dispatchability variations.

C.2 Inadvertent Flows

The simulation results presented in this document exclude the effects of inadvertent power flows. Inadvertent flows pose one of the trickiest of issues in all production cost modelling. The inadvertent flows problem has both engineering and economic aspects, although the economic ones are of most interest here.

Both BENCHMARK and EGEAS are proprietary products of the Electric Power Research Institute, Palo Alto, CA.

Inadvertent flows exist whenever system output exceeds or fails to meet load. In production cost models, it is impossible to represent the complexity of arrangements a utility may have to import and export power in times of system imbalance; hence, the simple concept of inadvertent flows is used. Whenever demand and supply are in imbalance, an inadvertent flow appears in outputs.

This approach, as mentioned above, is a necessary simplification of a complex problem, and, some accuracy problems result.

a. The question lingers whether this representation is a fair reflection of actual practice. Models are usually designed to avoid inadvertent flows at all costs. That is, models make unrealistically heroic efforts to keep supply and demand in balance. The true economics of the decision whether or not to import power is not well represented by such do-or-die rules. The inaccuracy can be mitigated by adding some intertie contracts as economically dispatched resources, but this does not fully resolve the question. In the case of BENCHMARK, the opportunities for inclusion of contracts is limited because it represents the system as one of the traditional isolated type.

b. In the absence of detailed contractual information, a token value is placed on inadvertent flows. Excess power, which has no market because it occurs at similar times on neighboring systems, is given a low or zero value. Emergency imports, being exactly opposite, are usually given an arbitrary high cost. Where such values are assigned in this study, electricity is sold at 1 cent/kWh and bought at 10 cents, both quite arbitrary choices.

c. Unfortunately, the economic impact of inadvertent flows on analysis results can be substantial because changes in the resource mix often have dramatic effects on the magnitude of flows. The addition of a large new resource will dramatically reduce shortfalls, improving the curtailability of a resource will reduce excess.

The combination of these problems creates a fatal situation. An aspect of the model in which little faith can be placed, which is based on arbitrary assumptions of costs, ends up driving the results. For fear of this effect, in this work, inadvertent flows are excluded from results. The negative of exclusion is the unrealistic nature of the test system. In the US, very few systems are isolated. The benefit of exclusion is that results are not driven by the arbitrariness of assumed values of flows.

C.3 Basic Analysis Procedure

Using Monte Carlo chronological models for analyzing options is a tedious procedure. Unlike optimizing models, such as EGEAS, the only way to compare options in a Monte Carlo chronological model is by tedious two-way comparisons between specified alternatives. Since the results are based on simple random samples, it is also important to keep random number streams equivalent between tests, and to keep an eye on the standard error of results.

Consider Table C-1, which is the basic annual summary output from BENCHMARK. This output report is equivalent to the one that appears in Section 4. The case presented in Table C-1 is the Minimum Capacity Case for 200 MW of gas-fired capacity. The general approach in all analyses is to adjust just one of the units in the roster. In this test, the unit of interest is number 17, GAS0340%. The 40% implies that in this run the GAS03 unit has a 40%, or 80 MW, minimum operating level. Notice that GAS0340% has an efficient average heat rate of 7959 Btu/kWh, and an equivalently low average cost of generation, 19.18 $/MWh.

Now, consider Table C-2, which is the source of the input data to the BENCHMARK run that generated the results of Table C-1. One of fundamental rules of production cost modelling concerns the heat rate curve, or I/O curve. This function must be convex for conventional notions of economic dispatch to work. That is, the marginal cost of generation must be increasing as the plant increases output. From a modelling standpoint, it is easy to see why this must be so. Since the generation units are dispatched in discrete blocks, there must be a clear choice of the cheapest resource to turn on next when load increases, or turn off when load declines. If a higher block of a unit produced at a price below that of a lower one, the choice of blocks could become unclear, a situation that cannot be resolved in current models. This convexity is freely assumed throughout the production cost modelling world, and is required by all models. Whether this assumption holds in practice, however, especially with combined cycles, is highly questionable (Wood and Wollenberg, 1982, ch. 2). Nonetheless, in this study, we have followed industry practice and imposed convexity on all heat rate curves, including those of combined cycles. The basis of the GAS0340% heat rate curve was one which appears in Table 1-3, based on the EPRI TAG. Table C-2 is simply a spreadsheet that caries out this convexity exercise. The unmarked values at the top are the parameters of a fitted exponential I/O function. In the industry, exponential or polynomial functions are always used to ensure convexity. In fact, heat rates for power plants are usually reported as the parameters of a suitable function rather than as raw data, which further fuels doubts about the validity of the convexity assumption. The columns of the main data block show various aspects of the heat rate curve for GAS0340%.

Notice that the heat rate at the minimum operating level is 10 kBtu/kWh. This heat rate shows that in this case the minimum operating level burden, as defined in section 5.4.1, is about 2 kBtu/kWh. The two blocks at the bottom of the spreadsheet show how this data is translated into BENCHMARK and EGEAS inputs. There is not space to fully explain why this translation is as it is, but the reader should note the striking difference in formats between EGEAS and BENCHMARK representations of the same data. This difference alone, should convince the reader of the difficulty of running parallel, comparable tests with different models.

Clearly, GAS0340% is a impressive new combined cycle. In Table C-3, a summary of the results in Table C-1 appears together with the equivalent results from three sister runs in which the minimum block size of GAS03 is adjusted according to the headings. Each run is summarized as a block of data that contains the contributions to total annual production costs of the startups and fuel burns of the fuels. In this test, the minimum operating level rises from left to right, so total costs increase. In the lower part of the spreadsheet, these cost changes are analyzed, and reduced to a cost in terms of dollars per kW of capacity. These calculations are conducted in two ways, with and without taking account of the inadvertent flows. The lower *IF* case ignores the effect of flows. These are the results that appear in Table 4-6. Notice that taking the flows into account would dramatically change the results, as asserted above. In this case, the net effect of excluding flows approximately doubles the result. However, the effect of flows can be quite unpredictable, and, consequently, the decision was made to omit them from the analysis.

Looking at these results in a little more detail, the effect of increasing the minimum block size has the expected effect on fuel costs. As the minimum block size increases, the gas bill of GeneLPo increases, while its coal bill declines. The effect on other fuels is small. Notice that the net effect of the changes on total costs is small, less that half a percent in all cases. This shows another of the irksome basic facts of production cost modelling life. The size of the effects are trivial compared to the uncertainties in some of the forecast assumptions, such as fuel prices. In fact, the electric utility industry comes under severe criticism for depending so heavily on models that, in an uncertain world claim to be able to measure differences at this level of detail. Conversely, the sums of money involved are huge, almost $4 million in the 80% case. Yearly costs of this magnitude over the life of a power plant represent huge sums.

C.4 Hourly Detail

Table C-4 shows the hourly output for one draw of one case of one week. The week presented is the week beginning at midnight on October 15, 1990. This table is typical of the output from a chronological production cost model. As mentioned in Section 5, the input data and reporting is hourly, by tradition. BENCHMARK follows, with most chronological models, in the tradition of the POWRSYM model developed at TVA. The simulation progresses over a week-long horizon. The output of every resource appears in the output table for each hour of the week.

In this particular simulation, both of the nuclear units are available, as are COL1-4. All of the remaining coal plants are on outage, as are most of the gas units. As a result, gas turbines are used extensively during this week, despite the low loads. The final part of Table C-4 shows the flows. In this week, there are only negative, that is, out, flows recorded. This, then, is a week with minimum load conditions.

C.5 Synergism Case

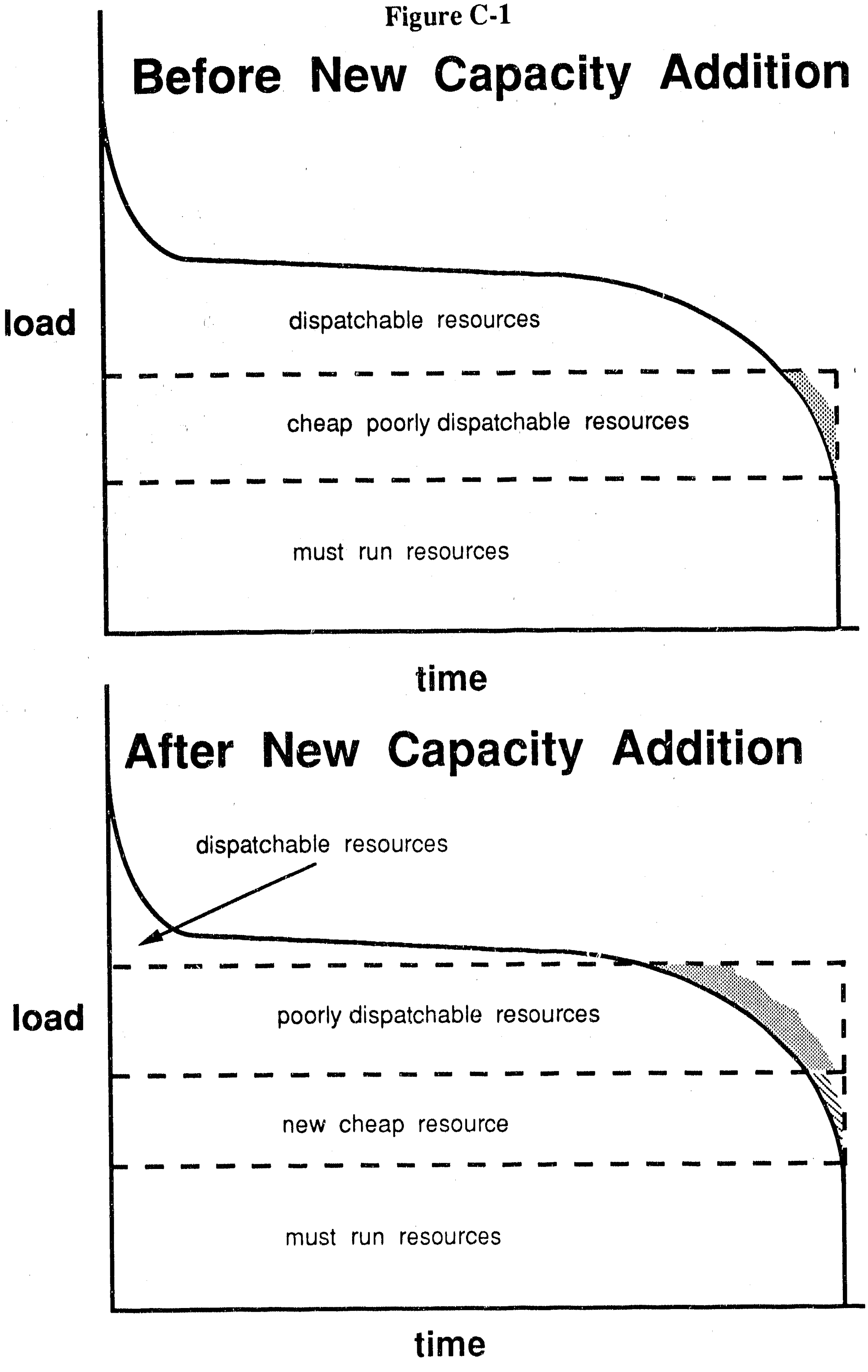
The synergism case reported in Section 4.3.3 requires a little more explanation than appears for the other cases. This case addresses the issue alluded to at several junctures in this report regarding the receptiveness of the pre-existing system to new resource additions. This case attempts to demonstrate that under some circumstances the the best strategy is not to plant the best possible seed, but also invest in some fertilizer.

Consider Figure C-1, which shows a start load duration curve (LDC) for a utility system, similar to the one shown in Section 2. An LDC is simply a convenient way of representing system loads. The load data is binned such that for each reported level of load experienced on the system, the time this load level was equaled or exceeded is recorded. Zero load is always exceeded, while higher levels of load are exceeded for less and less time. Hence the LDC typically has the shape shown in Figure C-1. The LDC is a helpful way to demonstrate some dispatchability questions, notably the minimum load problem.

In the Figure, the upper panel represents the pre-existing system. Note that, since a power unit appears on the y-axis and a time unit on the x-axis, the area under the curve represents the total amount of energy to be served. The must-run resources can be represented, as shown, by filling an area at the bottom of the LDC equal to their expected energy output. The operation of the cheap, and, usually, the less dispatchable of the remaining resources, can be demonstrated by filling in a second area above the must-run resources. The most dispatchable, and sometimes the most expensive, resources fill out the top of the LDC. Notice that being higher up in the LDC implies operation at a lower capacity factor, because the capacity factor is the area constrained by the LDC divided by the area of the equivalent rectangle. Notice also that filling the LDC in this way is slightly different to the approach implied in Section 2, in which the minimum blocks are treated separately from the upper blocks.

The fundamental limitation of the LDC framework for the purposes of detailed analysis, as alluded to in Section 4, is that chronology and some aspects of commitment cannot be well represented or considered. However, schematically at least, the minimum block problem can be represented. A must-run resource can be thought of as one that delivers only a full rectangle of

Figure C-1


Before New Capacity Addition
load
dispatchable resources
cheap poorly dispatchable resources
must run resources
time
After New Capacity Addition
dispatchable resources
load
poorly dispatchable resources
new cheap resource
must run resources
time

energy. It runs at all times, and can be represented here as running at a fixed power output. Notice that at the bottom of the LDC a full rectangle is exactly what is required, and, hence, there is not problem associated with this limitation. At the other extreme of the figure, the dispatchable resources can be curtailed at will and, consequently, the energy output can be exactly fitted to the area under the LDC. Again, this is exactly what is needed at the upper end of the LDC. In other words, the area under the LDC is very different from a perfect rectangle. Now consider the block marked *cheap poorly dispatchable resources* in the central part of the figure. The minimum load problem can be represented by recognizing that these resources will likely lie somewhere between the two others in terms of curtailability. The figure shows the full rectangle of energy that would be delivered if these were must-run resources. Conversely, the area bounded by the LDC represents the energy that would be served by these resources. The minimum load problem can, therefore, be represented by the poorly defined, shaded area of energy outside the LDC. This area represents unneeded energy that this resource delivers simply because output cannot be curtailed in keeping with the demands of the system operator. As mentioned above, this area is poorly defined, and is drawn to reflect this. It can also be thought of as an inadvertent flow as discussed in section C.2 above.

In the lower panel, a new resource has been added to this system. Typically, new resources will be more efficient and, therefore, cheaper than the pre-existing poorly dispatchable resources. The curtailability of the new resource will determine the size of any shaded area for the new resource, represented by the cross-hatched area. Reducing its size is clearly an important goal. Notice, however, that the addition of the new resource changes the roles of the pre-existing resources above it in the LDC.

Now consider the new role of the poorly dispatchable resource. It now has to be curtailed more, that is, the area bounded by the LDC is a smaller fraction of the rectangle. It is reasonable to assume that the shaded area will now also be larger than before. Whether the shaded area is a fixed fraction of that part of the rectangle outside the LDC, or, whether it is proportional to the length of the LDC segment within this resource's rectangle, the shaded area will be larger.

The behavior of this shaded area should show why a synergism might exist between the benefits of adding a new resource and improving the dispatchability of pre-existing resources. If a new resource is added in the absence of improvements to the pre-existing resources the increased burden of poor curtailment, represented by the shaded area, increases and detracts from the potential benefits of the new resource. On the other hand, if the curtailability of the pre-existing resource is improved in the absence of a new addition the potential benefits are limited by the small size of the shaded area. If both system improvements are made together, however, the potentially large negative benefit of the minimum load problem can be mitigated and more of the benefits of the new resource can be captured.

This simple argument should illuminate why there is reason to believe synergisms might exist and why not seeking them out is not giving fair consideration to new technologies. One final caveat to note concerns the static nature of the capacity addition that appears in the diagram. Over time, the LDC will shift upwards and/or some of the pre-exisiting capacity will be retired. In other words, other factors will tend to reduce the size of the shaded area in the lower panel and the synergism most likely will diminish over time. However, the cost savings generated by the synergism could still be large in the short run.

C.6 Bibliography

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Table C-1

90/08/02
17:40:43

1

---- GAS03 40% (200 MW) 1 Aug 17:52 ----

THERMAL UNIT DATA BY GROUP
REPORT PERIOD : 1 1 90 THROUGH 12 30 90
(AVERAGE FOR ALL DRAWS)

UNIT	NAME	CAP MW	CAP FCT(%) MEAN	CAP FCT(%) STND DEV.	NO.OF LIKE UNITS	ENERGY (GWH)	FUEL USEAGE MBTU (X1000)	FUEL USEAGE UNITS (X1000)	FUEL USEAGE STD UNIT	HT RATE BTU/KWH	START UPS	OPERATING COST FUEL COST(K$)	OPERATING COST VAR O&M (K$)	OPERATING COST FIXED COST(K$)	OPERATING COST START UP COST(K$)	OPERATING COST TOTAL COST(K$)	OPERATING COST TOTAL $/MWH
1	NUKE01	1000.	73.3	5.8	1	6404.2	64041.8	64041.8	MBTU	10000.	10.	64041.81	0.00	0.00	0.00	64041.81	10.00
2	NUKE02	1000.	75.6	6.4	1	6605.8	66057.8	66057.8	MBTU	10000.	9.	66057.80	0.00	0.00	0.00	66057.80	10.00
3	QF01	500.	100.0	0.0	1	4368.0	43680.1	43680.1	MBTU	10000.	0.	174720.58	0.00	0.00	0.00	174720.58	40.00
4	QF02	500.	100.0	0.0	1	4368.0	43680.1	43680.1	MBTU	10000.	0.	174720.58	0.00	0.00	0.00	174720.58	40.00
5	COL01	500.	61.2	5.0	1	2674.0	29760.4	29760.4	MBTU	11129.	9.	44640.55	0.00	0.00	172.00	44812.55	16.76
6	COL02	500.	62.1	4.2	1	2712.5	30005.4	30005.4	MBTU	11062.	8.	45008.17	0.00	0.00	167.20	45175.37	16.65
7	COL03	300.	66.6	2.8	1	1745.4	20116.9	20116.9	MBTU	11525.	6.	32187.09	0.00	0.00	107.80	32294.89	18.50
8	COL04	300.	68.2	3.1	1	1786.8	20528.8	20528.8	MBTU	11489.	5.	32846.09	0.00	0.00	91.70	32937.79	18.43
9	COL05	200.	35.0	3.4	1	611.9	7614.2	7614.2	MBTU	12444.	24.	12563.48	0.00	0.00	363.00	12926.47	21.13
10	COL06	200.	40.3	3.7	1	703.8	8751.0	8751.0	MBTU	12434.	27.	14439.22	0.00	0.00	405.60	14844.82	21.09
11	COL07	150.	39.0	3.9	1	511.7	5755.2	5755.2	MBTU	11248.	29.	9783.76	0.00	0.00	365.50	10149.26	19.84
12	COL08	150.	40.9	4.0	1	535.8	6032.8	6032.8	MBTU	11259.	29.	10255.70	0.00	0.00	368.50	10624.20	19.83
13	COL09	100.	14.7	2.9	1	128.5	1500.5	1500.5	MBTU	11680.	37.	2625.93	0.00	0.00	915.00	3540.93	27.56
14	COL10	100.	16.4	3.2	1	142.9	1672.5	1672.5	MBTU	11701.	40.	2926.87	0.00	0.00	1011.00	3937.87	27.55
15	GAS01	750.	33.8	3.9	1	2212.8	25852.9	25852.9	MBTU	11683.	11.	62046.98	0.00	0.00	371.00	62417.98	28.21
16	GAS02	750.	40.2	3.0	1	2636.0	30186.7	30186.7	MBTU	11452.	10.	72448.13	0.00	0.00	334.60	72782.73	27.61
17	GAS0340%	200.	66.6	3.4	1	1162.8	9255.3	9255.3	MBTU	7959.	7.	22212.82	0.00	0.00	90.50	22303.32	19.18
18	GAS04	200.	27.1	3.0	1	474.0	4790.9	4790.9	MBTU	10107.	13.	11498.26	0.00	0.00	161.00	11659.26	24.60
19	GAS05	125.	12.8	2.2	1	140.3	1632.2	1632.2	MBTU	11636.	12.	3917.37	0.00	0.00	91.80	4009.17	28.58
20	GAS06	125.	13.8	2.6	1	151.1	1741.8	1741.8	MBTU	11527.	12.	4180.28	0.00	0.00	92.10	4272.38	28.27
21	GAS07	100.	13.8	2.6	1	120.4	1448.7	1448.7	MBTU	12035.	13.	3476.89	0.00	0.00	63.60	3540.49	29.41

Table C-1 cont'd

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2

ELECTRIC POWER RESEARCH INSTITUTE   BENCHMARK 3.1

---- GAS03 40% (200 MW) 1 Aug 17:52 ----

THERMAL UNIT DATA BY GROUP
REPORT PERIOD : 1 1 90 THROUGH 12 30 90
(AVERAGE FOR ALL DRAWS)

UNIT	NAME	CAP MW	CAP FCT(%) MEAN	CAP FCT(%) STND DEV.	NO.OF LIKE UNITS	ENERGY (GWH)	FUEL USEAGE MBTU (X1000)	FUEL USEAGE UNITS (X1000)	FUEL USEAGE STD UNIT	HT RATE BTU/KWH	START UPS	OPERATING COST FUEL COST(K$)	OPERATING COST VAR O&M (K$)	OPERATING COST FIXED COST(K$)	OPERATING COST START UP COST(K$)	OPERATING COST TOTAL COST(K$)	OPERATING COST TOTAL $/MWH
22	GAS08	100.	13.2	2.7	1	115.4	1391.8	1391.8	MBTU	12058.	13.	3340.32	0.00	0.00	63.00	3403.32	29.48
23	GAS09	75.	12.9	2.7	1	84.8	951.2	951.2	MBTU	11221.	19.	2282.99	0.00	0.00	46.80	2329.79	27.48
24	GAS10	75.	14.1	2.8	1	92.7	1034.3	1034.3	MBTU	11164.	20.	2482.36	0.00	0.00	49.80	2532.16	27.33
25	OIL01	500.	14.3	2.7	1	624.2	7040.1	7040.1	MBTU	11279.	11.	16896.31	0.00	0.00	270.00	17166.31	27.50
26	OIL02	500.	16.4	2.3	1	714.9	7997.3	7997.3	MBTU	11187.	12.	19193.46	0.00	0.00	304.00	19497.46	27.27
27	CT01	150.	25.7	2.4	1	336.5	3367.7	3367.7	MBTU	10009.	300.	12965.77	0.00	0.00	299.72	13265.49	39.42
28	CT02	150.	29.0	2.1	1	379.7	3800.6	3800.6	MBTU	10009.	304.	14632.22	0.00	0.00	304.20	14936.42	39.34
29	CT03	125.	17.8	2.1	1	194.1	2136.7	2136.7	MBTU	11008.	256.	8226.38	0.00	0.00	256.08	8482.46	43.70
30	CT04	125.	21.3	2.3	1	232.1	2555.1	2555.1	MBTU	11008.	275.	9837.19	0.00	0.00	275.40	10112.59	43.57
31	CT05	100.	12.4	2.0	1	108.1	1298.6	1298.6	MBTU	12007.	212.	4999.44	0.00	0.00	211.72	5211.15	48.19
32	CT06	100.	14.8	2.2	1	129.1	1550.2	1550.2	MBTU	12008.	234.	5968.21	0.00	0.00	[illegible].08	6202.29	48.04
33	CT07	75.	9.1	1.6	1	59.8	778.1	778.1	MBTU	13006.	175.	2995.81	0.00	0.00	174.96	3170.77	53.00
34	CT08	75.	10.4	2.2	1	67.8	882.3	882.3	MBTU	13007.	191.	3396.96	0.00	0.00	191.24	3588.20	52.90
35	CT09	50.	6.8	1.7	1	29.6	414.8	414.8	MBTU	14005.	126.	1596.87	0.00	0.00	125.96	1722.83	58.17
36	CT10	50.	7.8	1.7	1	34.0	476.6	476.6	MBTU	14006.	148.	1834.94	0.00	0.00	147.52	1982.46	58.26
SYSTEM TOTAL :		10000.	49.7	0.2		43399.6	459781.8					977247.6	0.0	0.0	8126.4	985373.9	22.70

Table C-2

GAS 03 40% 1-Aug-90

300000
6000
100
0.005000
10000

MW	IO curve	deriv.	cnvx	chord	cnvx	av. hr	% eff.	avail.
80	800000.00	6000.75				10000.00		0.85
140	1140201.38	6001.01	yes	5670.02	yes	8144.30	41.89	0.85
180	1380245.96	6001.23	yes	6001.11	yes	7668.03	44.50	0.85
200	1500271.83	6001.36	yes	6001.29	yes	7501.36	45.49	0.85

block #	0	1	2	3	4	checks	
block size	0.0	80.0	140.0	180.0	200.0		
Heat Rate Input to BENCHMARK							
av. heat rate		10000.00	8144.30	7668.03	7501.36		
capacity in block	0	80	60	40	20		
incremental heat rate		10000	5670	6001	6001		
prob.	0.15	0.00	0.00	0.00	0.85	1.000	for= 0.150
Inputs to EGEAS							
cap. multiplier		0.400	0.300	0.200	0.100	1.000	
HR multiplier		1.333	0.756	0.800	0.800	1.000	
out. multiplier		1.000	0.000	0.000	0.000	1.000	

Table C-3

Effect of Min. Block Size on Fuel and Start-Up Costs - 200 MW Gas Unit

GeneLPo 2-Aug-90 200 MW GAS03

	20% case		40% case			
	start costs	fuel costs	start costs	fuel costs	diff. su	diff. fuel
NUKE	0.000	130.100	0.000	130.100	0.000	0.000
QF	0.000	349.441	0.000	349.441	0.000	0.000
COL-STM	3.956	207.395	3.967	207.277	0.011	-0.118
GAS-STM	1.360	186.596	1.364	187.886	0.004	1.290
OIL-STM	0.576	36.063	0.574	36.090	-0.002	0.027
CTs	2.222	66.415	2.221	66.454	-0.001	0.039
INADV-IN	0.000	22.351	0.000	22.353	0.000	0.002
INADV-OUT	0.000	-9.983	0.000	-10.633	0.000	-0.650
HYDRO	0.000	43.680	0.000	43.680	0.000	0.000
TOTALS	8.114	1032.058	8.126	1032.648	0.012	0.590
total cost		1040.172		1040.774		0.602
percent effect						0.058
$/kW						**3.01**
TOTALS (IF)	8.114	1019.690	8.126	1020.928	0.012	1.238
total cost		1027.804		1029.054		1.250
percent effect						0.122
$/kW						**6.25**

20% case -> minimum block size of the GAS3 200 MW gas unit is 40 MW, and capacity factor = 61%
40% case -> minimum block size of the GAS3 200 MW gas unit is 80 MW, and capacity factor = 67%
60% case -> minimum block size of the GAS3 200 MW gas unit is 120 MW, and capacity factor = 73%
80% case -> minimum block size of the GAS3 200 MW gas unit is 160 MW, and capacity factor = 79%

GeneLPo 2-Aug-90 200 MW (cont'd)

	60% case				80% case			
	start costs	fuel costs	diff. su	diff. fuel	start costs	fuel costs	diff. su	diff. fuel
NUKE	0.000	130.100	0.000	0.000	0.000	130.100	0.000	0.000
QF	0.000	349.441	0.000	0.000	0.000	349.441	0.000	0.000
COL-STM	3.975	207.131	0.019	-0.264	3.986	207.076	0.030	-0.319
GAS-STM	1.363	189.478	0.003	2.882	1.364	190.581	0.004	3.985
OIL-STM	0.573	36.121	-0.003	0.058	0.573	36.125	-0.003	0.062
CTs	2.221	66.480	-0.001	0.065	2.221	66.456	-0.001	0.041
INADV-IN	0.000	22.352	0.000	0.001	0.000	22.351	0.000	0.000
INADV-OUT	0.000	-11.312	0.000	-1.329	0.000	-12.013	0.000	-2.030
HYDRO	0.000	43.680	0.000	0.000	0.000	43.680	0.000	0.000
TOTALS	8.132	1033.471	0.018	1.413	8.144	1033.797	0.030	1.739
total cost		1041.603		1.431		1041.941		1.769
percent effect				0.138				0.170
$/kW				**7.15**				**8.85**
TOTALS (IF	8.132	1022.431	0.018	2.741	8.144	1023.459	0.030	3.769
total cost		1030.563		2.759		1031.603		3.799
percent effect				0.268				0.370
$/kW				**13.80**				**18.99**

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Table C-4

---- h00 CASE - Sat May 26 17:12:59 PDT 1990 ----

HOURLY OUTPUT OF UNITS IN HYDRO ENERGY ALLOCATION PERIOD 11, SIMULATION PERIOD 1,
FOR WEEK 2 DRAW 1

	NUKE01	NUKE02	QF01	QF02	COL01	COL02	COL03	COL04	GAS01	GAS02	GAS04	CT01	CT02	CT03	CT04
1	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
2	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
3	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
4	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
5	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
6	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
7	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	199.0	350.0	50.0	0.0	0.0	0.0	0.0
8	1000.0	1000.0	500.0	500.0	425.0	425.0	238.0	200.0	350.0	350.0	100.0	0.0	0.0	0.0	0.0
9	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	534.0	100.0	0.0	0.0	0.0	0.0
10	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	490.0	100.0	149.0	149.0	0.0	0.0
11	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	514.0	100.0	149.0	149.0	0.0	124.0
12	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	484.0	100.0	149.0	149.0	0.0	124.0
13	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	492.0	100.0	149.0	149.0	124.0	124.0
14	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	459.0	100.0	149.0	149.0	124.0	124.0
15	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	545.0	100.0	149.0	149.0	124.0	124.0
16	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	435.0	100.0	149.0	149.0	124.0	124.0
17	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	487.0	100.0	149.0	149.0	0.0	124.0
18	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	386.0	100.0	149.0	149.0	0.0	124.0
19	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	532.0	100.0	149.0	149.0	124.0	124.0
20	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	457.0	100.0	149.0	149.0	124.0	124.0
21	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	563.0	100.0	0.0	0.0	0.0	0.0
22	1000.0	1000.0	500.0	500.0	353.0	400.0	200.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
23	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	274.0	50.0	0.0	0.0	0.0	0.0
24	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
25	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
26	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
27	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
28	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
29	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
30	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
31	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	209.0	350.0	50.0	0.0	0.0	0.0	0.0
32	1000.0	1000.0	500.0	500.0	425.0	425.0	250.0	200.0	350.0	399.0	100.0	0.0	0.0	0.0	0.0
33	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	512.0	100.0	0.0	0.0	0.0	0.0
34	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	424.0	100.0	149.0	149.0	0.0	0.0
35	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	499.0	100.0	149.0	149.0	0.0	0.0
36	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	450.0	100.0	149.0	149.0	0.0	0.0
37	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	487.0	100.0	149.0	149.0	0.0	124.0
38	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	490.0	100.0	149.0	149.0	124.0	124.0
39	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	514.0	100.0	149.0	149.0	124.0	124.0
40	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	525.0	100.0	149.0	149.0	0.0	124.0
41	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	465.0	100.0	149.0	149.0	0.0	124.0
42	1000.0	1000.0	500.0	500.0	500.0	500.0	298.0	200.0	350.0	350.0	100.0	149.0	149.0	0.0	124.0
43	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	527.0	100.0	149.0	149.0	124.0	124.0
44	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	518.0	100.0	149.0	149.0	0.0	124.0
45	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	441.0	100.0	0.0	149.0	0.0	0.0

Table C-4 cont'd

HOURLY OUTPUT OF UNITS IN HYDRO ENERGY ALLOCATION PERIOD 11, SIMULATION PERIOD 1,
FOR WEEK 2 DRAW 1

	NUKE01	NUKE02	QF01	QF02	COL01	COL02	COL03	COL04	GAS01	GAS02	GAS04	CT01	CT02	CT03	CT04
46	1000.0	1000.0	500.0	500.0	366.0	400.0	200.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
47	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	338.0	50.0	0.0	0.0	0.0	0.0
48	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
49	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
50	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
51	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
52	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
53	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
54	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
55	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	216.0	350.0	50.0	0.0	0.0	0.0	0.0
56	1000.0	1000.0	500.0	500.0	425.0	425.0	250.0	200.0	350.0	383.0	100.0	0.0	0.0	0.0	0.0
57	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	429.0	100.0	0.0	0.0	0.0	0.0
58	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	483.0	100.0	0.0	149.0	0.0	0.0
59	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	471.0	100.0	149.0	149.0	0.0	0.0
60	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	375.0	100.0	149.0	149.0	0.0	0.0
61	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	530.0	100.0	149.0	149.0	0.0	0.0
62	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	533.0	100.0	149.0	149.0	0.0	124.0
63	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	532.0	100.0	149.0	149.0	0.0	124.0
64	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	495.0	100.0	149.0	149.0	0.0	0.0
65	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	470.0	100.0	149.0	149.0	0.0	0.0
66	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	404.0	100.0	149.0	149.0	0.0	0.0
67	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	529.0	100.0	149.0	149.0	124.0	124.0
68	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	535.0	100.0	149.0	149.0	0.0	0.0
69	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	532.0	100.0	0.0	0.0	0.0	0.0
70	1000.0	1000.0	500.0	500.0	353.0	400.0	200.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
71	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	194.0	50.0	0.0	0.0	0.0	0.0
72	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
73	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
74	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
75	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
76	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
77	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
78	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
79	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	191.0	350.0	50.0	0.0	0.0	0.0	0.0
80	1000.0	1000.0	500.0	500.0	425.0	425.0	250.0	200.0	350.0	391.0	100.0	0.0	0.0	0.0	0.0
81	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	513.0	100.0	0.0	0.0	0.0	0.0
82	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	518.0	100.0	0.0	149.0	0.0	0.0
83	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	510.0	100.0	0.0	149.0	0.0	0.0
84	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	414.0	100.0	0.0	149.0	0.0	0.0
85	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	547.0	100.0	0.0	149.0	0.0	0.0
86	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	420.0	100.0	149.0	149.0	0.0	0.0
87	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	511.0	100.0	0.0	149.0	0.0	0.0
88	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	479.0	100.0	0.0	0.0	0.0	0.0
89	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	568.0	100.0	0.0	0.0	0.0	0.0

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Table C-4 cont'd

HOURLY OUTPUT OF UNITS IN HYDRO ENERGY ALLOCATION PERIOD 11, SIMULATION PERIOD 1,
FOR WEEK 2 DRAW 1

	NUKE01	NUKE02	QF01	QF02	COL01	COL02	COL03	COL04	GAS01	GAS02	GAS04	CT01	CT02	CT03	CT04
90	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	453.0	100.0	149.0	149.0	0.0	0.0
91	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	500.0	100.0	149.0	149.0	124.0	124.0
92	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	476.0	100.0	149.0	149.0	0.0	124.0
93	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	550.0	100.0	0.0	0.0	0.0	0.0
94	1000.0	1000.0	500.0	500.0	347.0	400.0	200.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
95	1000.0	1000.0	500.0	500.0	200.0	228.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
96	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
97	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
98	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
99	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
100	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
101	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
102	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
103	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	308.0	50.0	0.0	0.0	0.0	0.0
104	1000.0	1000.0	500.0	500.0	425.0	425.0	250.0	200.0	350.0	502.0	100.0	0.0	0.0	0.0	0.0
105	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	527.0	100.0	0.0	0.0	0.0	0.0
106	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	459.0	100.0	149.0	149.0	0.0	0.0
107	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	557.0	100.0	0.0	149.0	0.0	0.0
108	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	428.0	100.0	0.0	149.0	0.0	0.0
109	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	520.0	100.0	0.0	149.0	0.0	0.0
110	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	511.0	100.0	0.0	149.0	0.0	0.0
111	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	467.0	100.0	0.0	149.0	0.0	0.0
112	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	508.0	100.0	0.0	0.0	0.0	0.0
113	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	485.0	100.0	0.0	0.0	0.0	0.0
114	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	545.0	100.0	0.0	0.0	0.0	0.0
115	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	472.0	100.0	149.0	149.0	0.0	0.0
116	1000.0	1000.0	500.0	500.0	500.0	500.0	300.0	200.0	350.0	504.0	100.0	0.0	0.0	0.0	0.0
117	1000.0	1000.0	500.0	500.0	498.0	500.0	200.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
118	1000.0	1000.0	500.0	500.0	300.0	300.0	176.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
119	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	248.0	50.0	0.0	0.0	0.0	0.0
120	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
121	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
122	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
123	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
124	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
125	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
126	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
127	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
128	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
129	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	216.0	50.0	0.0	0.0	0.0	0.0
130	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	342.0	350.0	50.0	0.0	0.0	0.0	0.0
131	1000.0	1000.0	500.0	500.0	300.0	300.0	184.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
132	1000.0	1000.0	500.0	500.0	300.0	300.0	160.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
133	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	184.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0

Table C-4 cont'd

ELECTRIC POWER RESEARCH INSTITUTE BENCHMARK 3.1
---- h00 CASE - Sat May 26 17:12:59 PDT 1990 ----

HOURLY OUTPUT OF UNITS IN HYDRO ENERGY ALLOCATION PERIOD 11, SIMULATION PERIOD 1,
FOR WEEK 2 DRAW 1

	NUKE01	NUKE02	QF01	QF02	COL01	COL02	COL03	COL04	GAS01	GAS02	GAS04	CT01	CT02	CT03	CT04
134	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	302.0	350.0	50.0	0.0	0.0	0.0	0.0
135	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	206.0	350.0	50.0	0.0	0.0	0.0	0.0
136	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	267.0	50.0	0.0	0.0	0.0	0.0
137	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	195.0	350.0	50.0	0.0	0.0	0.0	0.0
138	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	302.0	350.0	50.0	0.0	0.0	0.0	0.0
139	1000.0	1000.0	500.0	500.0	425.0	425.0	200.0	200.0	350.0	350.0	83.0	0.0	0.0	0.0	0.0
140	1000.0	1000.0	500.0	500.0	300.0	370.0	200.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
141	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	238.0	350.0	50.0	0.0	0.0	0.0	0.0
142	1000.0	1000.0	500.0	500.0	257.0	300.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
143	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
144	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
145	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
146	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
147	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
148	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
149	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
150	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
151	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
152	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
153	1000.0	1000.0	500.0	500.0	200.0	220.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
154	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	190.0	50.0	0.0	0.0	0.0	0.0
155	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	210.0	50.0	0.0	0.0	0.0	0.0
156	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	192.0	50.0	0.0	0.0	0.0	0.0
157	1000.0	1000.0	500.0	500.0	290.0	300.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
158	1000.0	1000.0	500.0	500.0	254.0	300.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
159	1000.0	1000.0	500.0	500.0	200.0	215.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
160	1000.0	1000.0	500.0	500.0	200.0	237.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
161	1000.0	1000.0	500.0	500.0	235.0	300.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
162	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	278.0	50.0	0.0	0.0	0.0	0.0
163	1000.0	1000.0	500.0	500.0	425.0	425.0	200.0	200.0	350.0	350.0	93.0	0.0	0.0	0.0	0.0
164	1000.0	1000.0	500.0	500.0	400.0	403.0	200.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
165	1000.0	1000.0	500.0	500.0	300.0	300.0	181.0	200.0	350.0	350.0	50.0	0.0	0.0	0.0	0.0
166	1000.0	1000.0	500.0	500.0	300.0	300.0	150.0	150.0	150.0	230.0	50.0	0.0	0.0	0.0	0.0
167	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
168	1000.0	1000.0	500.0	500.0	200.0	200.0	150.0	150.0	150.0	150.0	50.0	0.0	0.0	0.0	0.0
TOTAL	168000.	168000.	84000.	84000.	58528.	59048.	35837.	29334.	42700.	54160.	11926.	5662.	7450.	1364.	2852.
FUEL K$	1680.	1680.	3360.	3360.	1008.	1013.	672.	566.	1379.	1580.	308.	218.	287.	58.	121.
CAP_FC%	100.	100.	100.	100.	70.	70.	71.	58.	34.	43.	35.	22.	30.	6.	14.
USE_FC%	100.	100.	100.	100.	70.	70.	71.	58.	34.	43.	35.	99.	99.	99.	99.
STARTS	0	0	0	0	0	0	0	0	0	0	0	7	7	6	5
SER_HRS	168	168	168	168	168	168	168	168	168	168	168	38	50	11	23

Table C-4 cont'd

90/08/17
01:42:09

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HOURLY OUTPUT OF UNITS IN HYDRO ENERGY ALLOCATION PERIOD 11, SIMULATION PERIOD 1,
FOR WEEK 2 DRAW 1

	CT05	CT08	TOT HYDR	TIE FLOW	LOAD	XS RESRV	INC COST	DEC COST	FUEL K$
1	0.0	0.0	1000.0	-1001.0	4049.0	0.0	10.0	10.0	91.1
2	0.0	0.0	1000.0	-1065.0	3985.0	2115.8	10.0	10.0	91.1
3	0.0	0.0	1000.0	-1125.0	3925.0	2178.8	10.0	10.0	91.1
4	0.0	0.0	1000.0	-1097.0	3953.0	2149.4	10.0	10.0	91.1
5	0.0	0.0	1000.0	-985.0	4065.0	2031.8	10.0	10.0	91.1
6	0.0	0.0	1000.0	-476.0	4574.0	1497.3	10.0	10.0	91.1
7	0.0	0.0	1000.0	0.0	5499.0	526.1	9.7	9.7	94.4
8	0.0	0.0	1000.0	0.0	6088.0	207.6	16.1	16.1	101.9
9	0.0	0.0	1000.0	0.0	6484.0	41.8	19.4	19.4	108.7
10	0.0	0.0	1000.0	0.0	6738.0	75.1	19.4	19.4	119.3
11	0.0	0.0	1000.0	0.0	6886.0	44.7	19.4	19.4	125.1
12	0.0	0.0	1000.0	0.0	6856.0	76.2	19.4	19.4	124.5
13	0.0	0.0	1000.0	0.0	6988.0	62.6	19.4	19.4	129.9
14	99.0	0.0	1000.0	0.0	7054.0	93.3	19.4	19.4	133.8
15	0.0	0.0	1000.0	0.0	7041.0	7.0	19.4	19.4	130.9
16	0.0	0.0	1000.0	0.0	6931.0	122.5	19.4	19.4	128.8
17	0.0	0.0	1000.0	0.0	6859.0	73.1	19.4	19.4	124.5
18	0.0	0.0	1000.0	0.0	6758.0	179.1	19.4	19.4	122.6
19	99.0	74.0	1000.0	0.0	7201.0	14.0	19.4	10.0	139.0
20	0.0	0.0	1000.0	0.0	6953.0	99.4	19.4	19.4	129.2
21	0.0	0.0	1000.0	0.0	6513.0	11.4	20.3	20.3	109.3
22	0.0	0.0	1000.0	0.0	5903.0	651.9	14.4	14.4	99.0
23	0.0	0.0	1000.0	0.0	5374.0	1135.3	9.7	9.7	93.2
24	0.0	0.0	1000.0	-348.0	4702.0	1662.9	10.0	10.0	91.1
25	0.0	0.0	1000.0	-640.0	4410.0	1669.5	10.0	10.0	91.1
26	0.0	0.0	1000.0	-796.0	4254.0	1833.3	10.0	10.0	91.1
27	0.0	0.0	1000.0	-869.0	4181.0	1910.0	10.0	10.0	91.1
28	0.0	0.0	1000.0	-897.0	4153.0	1939.4	10.0	10.0	91.1
29	0.0	0.0	1000.0	-785.0	4265.0	1821.8	10.0	10.0	91.1
30	0.0	0.0	1000.0	-398.0	4652.0	1415.4	10.0	10.0	91.1
31	0.0	0.0	1000.0	0.0	5509.0	515.6	9.7	9.7	94.5
32	0.0	0.0	1000.0	0.0	6149.0	143.6	19.4	19.4	103.0
33	0.0	0.0	1000.0	0.0	6462.0	64.9	19.4	19.4	108.3
34	0.0	0.0	1000.0	0.0	6672.0	144.4	19.4	19.4	118.1
35	0.0	0.0	1000.0	0.0	6747.0	65.7	19.4	19.4	119.5
36	0.0	0.0	1000.0	0.0	6698.0	117.1	19.4	19.4	118.6
37	0.0	0.0	1000.0	0.0	6859.0	73.1	19.4	19.4	124.5
38	0.0	0.0	1000.0	0.0	6986.0	64.7	19.4	19.4	129.9
39	0.0	0.0	1000.0	0.0	7010.0	39.5	19.4	19.4	130.3
40	0.0	0.0	1000.0	0.0	6897.0	33.2	19.4	19.4	125.3
41	0.0	0.0	1000.0	0.0	6837.0	96.2	19.4	19.4	124.1
42	0.0	0.0	1000.0	0.0	6720.0	219.0	16.2	16.2	121.9
43	99.0	0.0	1000.0	0.0	7122.0	21.9	19.4	10.0	135.2
44	0.0	0.0	1000.0	0.0	6890.0	40.5	19.4	19.4	125.2
45	0.0	0.0	1000.0	0.0	6540.0	133.0	19.4	19.4	112.7

Table C-4 cont'd

HOURLY OUTPUT OF UNITS IN HYDRO ENERGY ALLOCATION PERIOD 11, SIMULATION PERIOD 1,
FOR WEEK 2 DRAW 1

	CT05	CT08	TOT HYDR	TIE FLOW	LOAD	XS RESRV	INC COST	DEC COST	FUEL K$
46	0.0	0.0	1000.0	0.0	5916.0	638.2	14.4	14.4	99.2
47	0.0	0.0	1000.0	0.0	5438.0	1081.1	9.7	9.7	93.8
48	0.0	0.0	1000.0	-320.0	4730.0	1633.5	10.0	10.0	91.1
49	0.0	0.0	1000.0	-616.0	4434.0	1644.3	10.0	10.0	91.1
50	0.0	0.0	1000.0	-772.0	4278.0	1808.1	10.0	10.0	91.1
51	0.0	0.0	1000.0	-859.0	4191.0	1899.5	10.0	10.0	91.1
52	0.0	0.0	1000.0	-893.0	4157.0	1935.2	10.0	10.0	91.1
53	0.0	0.0	1000.0	-783.0	4267.0	1819.7	10.0	10.0	91.1
54	0.0	0.0	1000.0	-334.0	4716.0	1348.2	10.0	10.0	91.1
55	0.0	0.0	1000.0	0.0	5516.0	508.2	9.7	9.7	94.5
56	0.0	0.0	1000.0	0.0	6133.0	160.4	19.4	19.4	102.7
57	0.0	0.0	1000.0	0.0	6379.0	152.1	19.4	19.4	106.7
58	0.0	0.0	1000.0	0.0	6582.0	88.9	19.4	19.4	113.5
59	0.0	0.0	1000.0	0.0	6719.0	95.1	19.4	19.4	119.0
60	0.0	0.0	1000.0	0.0	6623.0	195.9	19.4	19.4	117.1
61	0.0	0.0	1000.0	0.0	6778.0	33.1	19.4	19.4	120.1
62	0.0	0.0	1000.0	0.0	6905.0	24.8	19.4	19.4	125.4
63	0.0	0.0	1000.0	0.0	6904.0	25.8	19.4	19.4	125.4
64	0.0	0.0	1000.0	0.0	6743.0	69.9	19.4	19.4	119.4
65	0.0	0.0	1000.0	0.0	6718.0	96.1	19.4	19.4	119.0
66	0.0	0.0	1000.0	0.0	6652.0	165.4	19.4	19.4	117.7
67	0.0	0.0	1000.0	0.0	7025.0	23.8	19.4	10.0	130.6
68	0.0	0.0	1000.0	0.0	6783.0	27.9	19.4	19.4	120.2
69	0.0	0.0	1000.0	0.0	6482.0	43.9	19.4	19.4	108.7
70	0.0	0.0	1000.0	0.0	5903.0	651.9	14.4	14.4	99.0
71	0.0	0.0	1000.0	0.0	5294.0	1219.3	9.7	9.7	92.4
72	0.0	0.0	1000.0	-398.0	4652.0	1659.4	10.0	10.0	91.1
73	0.0	0.0	1000.0	-670.0	4380.0	1701.0	10.0	10.0	91.1
74	0.0	0.0	1000.0	-812.0	4238.0	1850.1	10.0	10.0	91.1
75	0.0	0.0	1000.0	-872.0	4178.0	1913.1	10.0	10.0	91.1
76	0.0	0.0	1000.0	-885.0	4165.0	1926.8	10.0	10.0	91.1
77	0.0	0.0	1000.0	-804.0	4246.0	1841.7	10.0	10.0	91.1
78	0.0	0.0	1000.0	-346.0	4704.0	1360.8	10.0	10.0	91.1
79	0.0	0.0	1000.0	0.0	5491.0	534.5	9.7	9.7	94.3
80	0.0	0.0	1000.0	0.0	6141.0	152.0	19.4	19.4	102.9
81	0.0	0.0	1000.0	0.0	6463.0	63.9	19.4	19.4	108.3
82	0.0	0.0	1000.0	0.0	6617.0	52.2	19.4	19.4	114.2
83	0.0	0.0	1000.0	0.0	6609.0	60.6	19.4	19.4	114.0
84	0.0	0.0	1000.0	0.0	6513.0	161.4	19.4	19.4	112.1
85	0.0	0.0	1000.0	0.0	6646.0	21.7	19.4	19.4	114.7
86	0.0	0.0	1000.0	0.0	6668.0	148.6	19.4	19.4	118.0
87	0.0	0.0	1000.0	0.0	6610.0	59.5	19.4	19.4	114.0
88	0.0	0.0	1000.0	0.0	6429.0	99.6	19.4	19.4	107.7
89	0.0	0.0	1000.0	0.0	6518.0	6.1	20.3	20.3	109.4

Table C-4 cont'd

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HOURLY OUTPUT OF UNITS IN HYDRO ENERGY ALLOCATION PERIOD 11, SIMULATION PERIOD 1,
FOR WEEK 2 DRAW 1

	CT05	CT08	TOT HYDR	TIE FLOW	LOAD	XS RESRV	INC COST	DEC COST	FUEL K$
90	0.0	0.0	1000.0	0.0	6701.0	114.0	19.4	19.4	118.6
91	99.0	0.0	1000.0	0.0	7095.0	50.3	19.4	10.0	134.6
92	0.0	0.0	1000.0	0.0	6848.0	84.6	19.4	19.4	124.3
93	0.0	0.0	1000.0	0.0	6500.0	25.0	20.3	19.4	109.0
94	0.0	0.0	1000.0	0.0	5897.0	658.2	14.4	14.4	99.0
95	0.0	0.0	1000.0	0.0	5078.0	1440.1	4.1	4.1	91.3
96	0.0	0.0	1000.0	-184.0	4866.0	1218.7	10.0	10.0	91.1
97	0.0	0.0	1000.0	-496.0	4554.0	1518.3	10.0	10.0	91.1
98	0.0	0.0	1000.0	-596.0	4454.0	1623.3	10.0	10.0	91.1
99	0.0	0.0	1000.0	-668.0	4382.0	1698.9	10.0	10.0	91.1
100	0.0	0.0	1000.0	-685.0	4365.0	1716.8	10.0	10.0	91.1
101	0.0	0.0	1000.0	-584.0	4466.0	1610.7	10.0	10.0	91.1
102	0.0	0.0	1000.0	-151.0	4899.0	1156.1	10.0	10.0	91.1
103	0.0	0.0	1000.0	0.0	5408.0	621.6	9.7	9.7	93.5
104	0.0	0.0	1000.0	0.0	6252.0	35.4	19.4	19.4	105.0
105	0.0	0.0	1000.0	0.0	6477.0	49.2	19.4	19.4	108.6
106	0.0	0.0	1000.0	0.0	6707.0	107.7	19.4	19.4	118.7
107	0.0	0.0	1000.0	0.0	6656.0	11.2	20.3	20.3	114.9
108	0.0	0.0	1000.0	0.0	6527.0	146.7	19.4	19.4	112.4
109	0.0	0.0	1000.0	0.0	6619.0	50.1	19.4	19.4	114.2
110	0.0	0.0	1000.0	0.0	6610.0	59.5	19.4	19.4	114.0
111	0.0	0.0	1000.0	0.0	6566.0	105.7	19.4	19.4	113.2
112	0.0	0.0	1000.0	0.0	6458.0	69.1	19.4	19.4	108.2
113	0.0	0.0	1000.0	0.0	6435.0	93.3	19.4	19.4	107.8
114	0.0	0.0	1000.0	0.0	6495.0	30.3	19.4	19.4	108.9
115	0.0	0.0	1000.0	0.0	6720.0	94.0	19.4	10.0	119.0
116	0.0	0.0	1000.0	0.0	6454.0	73.3	19.4	19.4	108.1
117	0.0	0.0	1000.0	0.0	6148.0	44.6	15.0	15.0	102.7
118	0.0	0.0	1000.0	0.0	5726.0	487.7	10.2	10.2	96.6
119	0.0	0.0	1000.0	0.0	5348.0	834.6	9.7	9.7	92.9
120	0.0	0.0	1000.0	-246.0	4804.0	1205.8	10.0	10.0	91.1
121	0.0	0.0	1000.0	-571.0	4479.0	1247.1	10.0	10.0	91.1
122	0.0	0.0	1000.0	-744.0	4306.0	1428.7	10.0	10.0	91.1
123	0.0	0.0	1000.0	-880.0	4170.0	1571.5	10.0	10.0	91.1
124	0.0	0.0	1000.0	-928.0	4122.0	1621.9	10.0	10.0	91.1
125	0.0	0.0	1000.0	-909.0	4141.0	1952.0	10.0	10.0	91.1
126	0.0	0.0	1000.0	-822.0	4228.0	1860.6	10.0	10.0	91.1
127	0.0	0.0	1000.0	-584.0	4466.0	1610.7	10.0	10.0	91.1
128	0.0	0.0	1000.0	-227.0	4823.0	1235.9	10.0	10.0	91.1
129	0.0	0.0	1000.0	0.0	5316.0	718.2	9.7	9.7	92.6
130	0.0	0.0	1000.0	0.0	5642.0	641.9	9.7	9.7	95.7
131	0.0	0.0	1000.0	0.0	5734.0	579.3	10.2	10.2	96.7
132	0.0	0.0	1000.0	0.0	5710.0	638.5	10.2	10.2	96.4
133	0.0	0.0	1000.0	0.0	5684.0	641.8	10.2	10.2	96.2

Table C-4 cont'd

ELECTRIC POWER RESEARCH INSTITUTE BENCHMARK 3.1
---- h00 CASE - Sat May 26 17:12:59 PDT 1990 ----

HOURLY OUTPUT OF UNITS IN HYDRO ENERGY ALLOCATION PERIOD 11, SIMULATION PERIOD 1,
FOR WEEK 2 DRAW 1

	CT05	CT08	TOT HYDR	TIE FLOW	LOAD	XS RESRV	INC COST	DEC COST	FUEL K$
134	0.0	0.0	1000.0	0.0	5602.0	717.9	9.7	9.7	95.4
135	0.0	0.0	1000.0	0.0	5506.0	818.7	9.7	9.7	94.4
136	0.0	0.0	1000.0	0.0	5367.0	964.7	9.7	9.7	93.1
137	0.0	0.0	1000.0	0.0	5495.0	830.2	9.7	9.7	94.3
138	0.0	0.0	1000.0	0.0	5602.0	717.9	9.7	9.7	95.4
139	0.0	0.0	1000.0	0.0	6033.0	265.4	15.0	10.0	101.0
140	0.0	0.0	1000.0	0.0	5820.0	722.0	14.4	14.4	97.9
141	0.0	0.0	1000.0	0.0	5538.0	905.1	9.7	9.7	94.7
142	0.0	0.0	1000.0	0.0	5207.0	1132.7	4.1	4.1	91.8
143	0.0	0.0	1000.0	-84.0	4966.0	1242.7	10.0	10.0	91.1
144	0.0	0.0	1000.0	-484.0	4566.0	1505.7	10.0	10.0	91.1
145	0.0	0.0	1000.0	-781.0	4269.0	1817.6	10.0	10.0	91.1
146	0.0	0.0	1000.0	-948.0	4102.0	1992.9	10.0	10.0	91.1
147	0.0	0.0	1000.0	-1015.0	4035.0	2063.3	10.0	10.0	91.1
148	0.0	0.0	1000.0	-1026.0	4024.0	2074.8	10.0	10.0	91.1
149	0.0	0.0	1000.0	-1003.0	4047.0	2050.7	10.0	10.0	91.1
150	0.0	0.0	1000.0	-940.0	4110.0	1984.5	10.0	10.0	91.1
151	0.0	0.0	1000.0	-739.0	4311.0	1773.5	10.0	10.0	91.1
152	0.0	0.0	1000.0	-405.0	4645.0	1422.8	10.0	10.0	91.1
153	0.0	0.0	1000.0	0.0	5070.0	976.5	4.1	4.1	91.2
154	0.0	0.0	1000.0	0.0	5290.0	765.5	9.7	9.7	92.3
155	0.0	0.0	1000.0	0.0	5310.0	964.5	9.7	9.7	92.5
156	0.0	0.0	1000.0	0.0	5292.0	1003.4	9.7	9.7	92.4
157	0.0	0.0	1000.0	0.0	5240.0	1040.0	4.1	4.1	91.9
158	0.0	0.0	1000.0	0.0	5204.0	1025.8	4.1	4.1	91.8
159	0.0	0.0	1000.0	0.0	5065.0	1135.8	4.1	4.1	91.2
160	0.0	0.0	1000.0	0.0	5087.0	973.7	4.1	4.1	91.3
161	0.0	0.0	1000.0	0.0	5185.0	892.8	4.1	4.1	91.7
162	0.0	0.0	1000.0	0.0	5378.0	788.1	9.7	9.7	93.2
163	0.0	0.0	1000.0	0.0	6043.0	254.9	15.0	10.0	101.2
164	0.0	0.0	1000.0	0.0	5953.0	592.4	15.0	15.0	99.8
165	0.0	0.0	1000.0	0.0	5731.0	782.5	10.2	10.2	96.7
166	0.0	0.0	1000.0	0.0	5330.0	1034.5	9.7	9.7	92.7
167	0.0	0.0	1000.0	-196.0	4854.0	1483.3	10.0	10.0	91.1
168	0.0	0.0	1000.0	-658.0	4392.0	1688.4	10.0	10.0	91.1

TOTAL	396.	74.	168000.
FUEL K$	18.	4.	0.
CAP_FC%	2.	1.	100.
USE_FC%	99.	99.	100.
STARTS	4	1	0
SER_HRS	4	1	168

TOTAL SYSTEM COST (K$) FUEL 17313. STARTUP 0.0, TOTAL VARIABLE O&M 840.0
TOTAL LOAD (MWH) 943931

END

DATE FILMED

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