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EVALUATION OF TOOLS FOR RENEWABLE ENERGY POLICY ANALYSIS: THE RENEWABLE ENERGY PENETRATION MODEL

Panel on
Evaluation of
Renewable Energy Models

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PANEL ON
EVALUATION OF RENEWABLE ENERGY MODELS

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FOREWORD

It is a very difficult task to assess the extensive amount of work that is represented by the Renewable Energy Penetration Model. It is even more difficult to evaluate how the results of that model will simulate future scenarios. To accomplish these tasks, the panelists studied all available documents and presentations, and had comprehensive discussions with the modelers, at meetings and via telephone. In addition, the modelers made special sets of sensitivity runs which were of interest to the assessment panel. These runs included changes in inputs, parameters and model components, as well as the addition of new model output categories.

Based upon their areas of expertise and interests, the panelists then chose primary and secondary responsibilities for the assessment of various REP Model modules and capabilities: Demand & Load, Capacity Expansion, Dispatch/Production Costing, Storage, Renewables, Transmission, Reliability, Finance & Regulatory, Environmental Effects, Policy Controls, Scenario Costing, and Structure/Feedback/Tradeoffs. The assessment of each of these modules and capabilities was discussed individually and with regard to the implications for the other sections of the model, and with regard to the overall results of the model. Various areas were combined as a result of these discussions.

The individual assessment sections inlcude discussions of quality of information, alternative methodologies, endogenous/exgenous treatments, different levels of detail, test results and other model runs, evidence of performance, treatment of risk, possible biases of data and methodology, appropriate and inappropriate applications, quality of documentation, usability of model, future enhancements and improvements that would be suggested, and the best guess on payoffs in terms of increased applicability, accuracy, and so on.

The assessment panel did an excellent and thorough job of assimilating all the information and discussing the ramifications. They deserve great thanks for their efforts, as do the following people. The time and information of Joe Galdo and other Department of Energy people was extremely helpful. Gary Gordon and Joe Baker provided outstanding support, and Joe Baker, in particular, was the perfect leader and facilitator for this difficult project.

Jim Gruhl
Evaluation Panel Chairman

Chapter 1
INTRODUCTION AND SUMMARY OF FINDINGS

PROJECT DESCRIPTION

The Energy Policy Act of 1992 establishes a program to support development of renewable energy technologies including a production incentive to public power utilities.[1] Because there is a wide range of possible policy actions that could be taken to increase electric market share for renewables, modeling tools are needed to help make informed decisions regarding future policy.

Previous energy modeling tools did not contain the regional or infrastructure focus necessary to examine renewable technologies. As a result, the Department of Energy Office of Utility Technologies (OUT) supported the development of tools for renewable energy policy analysis. Three models were developed: The Renewable Energy Penetration (REP) model, which is a spreadsheet model for determining first-order estimates of policy effects for each of the ten federal regions; the Ten Federal Region Model (TFRM), which employs utility capacity expansion and dispatching decisions; and the Regional Electric Policy Analysis Model (REPAM) which was constructed to allow detailed insight into interactions between policy and technology within an individual region.[2] Sandia National Laboratories Strategic Technologies developed the TFRM and REPAM; Princeton Economic Research Inc. (PERI) developed the REP model. These models were developed to provide a suite of fast, personal-computer based policy analysis tools; as one moves from the REP model to the TFRM to the REPAM the level of detail (and complexity) increases. Thus, an analyst could use the REP model to define several likely policy actions from a large group of candidate policies; the TFRM and REPAM could then be used to further explore these likely policies.

In 1993, the Office of Utility Technologies supported the Oak Ridge Institute for Science and Education (ORISE) to form an expert panel to provide an independent review of the REP model and TFRM. This panel was to identify model strengths, weaknesses (including any potential biases) in the models and to suggest potential improvements in the models. This report contains the panel's evaluation of the REP model; the TFRM is evaluated in a companion report. The panel did not review the REPAM.

In November of 1993 the panel was briefed on the TFRM and the REP model by Sandia National Laboratories and the staff of Princeton Economic Research Inc. The panel then developed a set of simulations for the models to assist in the evaluation (see Appendix B). The panel met for a second time in January 1994 to discuss model simulations and deliberate regarding evaluation outcomes. This report is largely a result of this second meeting.

The report is organized as follows. The remainder of this chapter provides a description of the REP model and summarizes the panel's findings. This chapter is followed by individual chapters that examine various aspects of the model: demand and load, capacity expansion, dispatching and production costing, reliability, renewables, storage, transmission, financial and regulatory concerns, and environmental effects.

REP MODEL DESCRIPTION[3]

The REP model is a technology assessment model designed specifically for use by non-modelers (e.g., program managers, policy analysts). The model is constructed to provide a straightforward, transparent and easily understood approach for generating approximate simulations of various policy options and tracks how effectively renewable energy systems compete with conventional systems. The model is not designed to replace the detailed and complex utility expansion models such as EGEAS and PROVIEW® but rather to be used as a complimentary tool to help define the policy space in which to further explore policy options using the detailed models.[4] The spreadsheet medium allows all REP model data to be readily accessible allowing for quick turnaround.

The REP model examines each of the ten federal regions individually. For each region, the REP model examines cost and performance of renewable technologies, the installed capacity mix in regions, and fuel cost projections to estimate the relative cost of renewable energy technologies and conventional technologies. The model assumes that renewable technology will begin to be adopted at the point of cost parity, although constraints on this renewable technology adoption such as risk aversion to new technologies, manufacturing capacity for renewable assets, utility diversity and reliability considerations, and renewable resource base within a region can limit penetration.

The REP model has two components. The first component examines intermittent technologies which are assumed to be fuel savers (i.e, they replace conventional fuels and therefore compete with installed utility capacity). Levelized capital and operating costs (LCOE) of intermittent renewable technologies (wind, photovoltaics and solar thermal) are adjusted by a risk premium (associated with technology maturity) to account for the higher risk of new technologies. The risk adjusted LCOE is then compared to the LCOE (fuel and operation and maintenance only) of a utility's conventional technologies. As the ratio of renewable LCOE to conventional LCOE decreases, the REP model assumes that the probability of renewable adoption will increase. A number of constraints and limits (e.g., resource availability, renewable manufacturing capacity) can be placed on this rate of adoption.

The second REP model component examines dispatchable technologies; unlike the intermittents these compete directly with conventional capacity additions. Dispatchable renewable technologies include geothermal, biomass and solar thermal with gas backup. The REP model calculates a risk adjusted LCOE similar to that for intermittent technologies. The risk adjusted LCOE of dispatchable renewables is compared to the LCOE (including capital costs) of conventional systems, and the total potential market for new plant capacity and retrofit is divided between the technologies using a logit function.

SUMMARY OF FINDINGS

Intended Applications

According to the modelers, the REP model is intended "to provide quick answers to questions ... where there is no time to gear up a detailed model."[5] The model's approach is to incorporate amplifying assumptions to permit program managers and policy analysis to "rapidly evaluate a wider range of scenarios."[6] The REP model estimates adoption potential for various renewable energy sources across several dimensions: areas of the country, years, different costs and performances, tax credits, carbon taxes, and other legislative and regulatory initiatives.

The evaluation panel feels that the REP model fills an important niche in the set of policy models by providing a quick turn-around, national policy model which can be used to investigate the role of renewable energy technologies in the United States. Some of the renewable energy issues that can be investigated include the effects of: capital cost and operating cost improvements, renewable tax incentives, fossil tax disincentives, efficiency improvements, regional variations in performances and site availability, competition between renewables and between fossil technologies and renewables, changes in risks associated with renewables, and other policies and issues.

The panel feels that the greatest value of this model is in the near-term, and is dependent upon the quality of input data, support analysis from more detailed models, and the familiarity of the user with the constraints and requirements of the model. The limitations of the REP model, the panel feels, will become more apparent in time, as other more detailed models are available that incorporate REP model capabilities.

Structure

The structure of the REP model is basically three spreadsheets of formulas with pre-processors and post-processors. The spreadsheets are programmed on Lotus 1-2-3 version 2.2 and include input, market analysis, and results spreadsheets. Summaries can be stacked and can be printed for all ten federal regions, or for just one federal region.

The structure of the REP model was dictated by the initial assumption that a quick turn-around spreadsheet model was needed. To the extent possible, pre-processors and assumptions have been used to approximate more complex effects. Feedbacks of cost of energy to change the level of demand, and other feedback relations, must be accomplished by the user in out-of-model feasibility checks, output-to-input calculations, and additional scenarios.

The model results are dictated by constraints and ratios. However, the methodology and data are transparent. This model, with additional outputs and documentation, would be highly accessible to analysts on a quick turn-around basis.

A shortcoming of the model is that it requires data that is not readily available, such as data on risk premiums, grid limits, manufacturing capabilities, and so on. On the contrary, this might be viewed as a model strength, as other models are not capable of using such information, and it may well dictate the actual responses of the energy system.

Demand

Demand modeling requires close attention from the user. Conservation, independent producers, and demand-side management effects must all be backed out of the load seen by the electric system. Without this attention, the model will obviously bias in favor of supply-side solutions, including renewables. A helpful addition here might be to use a post-processor to generate the demands that would be consistent with costs of electricity in various years. The user could then immediately see if changes in demand inputs were necessary.

Capacity Expansion

The REP model provides quick solutions to a complex expansion problem, with a straightforward and reasonable method. The approach is transparent. The limitations of this simplistic approach, however, are substantial. There is no production costing to help the selection of capacities and technologies are segregated into specific roles. Unless the user can understand these areas and guide the solutions appropriately, economic and capacity factor complexities will be missed.

The model assumptions seem to favor renewables over turbines. However, it is difficult to unravel any such bias without several model runs and flagging of constrained results. The conventional technologies have to be squashed down in a predetermined end mix. As a result, groups of renewables that can complement the conventional mix will be favored over renewables with similar load-meeting characteristics. The absence of storage heightens this problem.

Reliability

The conceptual approach to reliability in the REP model is an improvement over the full-capacity/no-capacity credit approaches that other models use for intermittent renewable energy technologies (IRET). A principal weakness is the need to do reliability planning off-line and the use of an approximation method that can introduce a substantial amount of cumulative error if used for long-run expansion plans. Using intermittent renewables to displace conventional technologies is the appropriate direction, and reasonable results are evident in the outputs of sensitivity runs and previous testing. One problem occurs in the linear credits given renewables, especially in meeting the peaking demands. One renewable unit, such as wind or solar, will have a good chance of meeting some peaking demand. However, many units in the same region will not meet multiples of that peaking credit because their energy supply times will be highly correlated. The bias here is in favor of renewables displacing too much gas turbine capacity, unless the user carefully tunes down the energy credit of large quantities of solar or wind in a region.

Dispatch

This model has only a very small amount of endogenous dispatching decision-making capability. This inability is somewhat compounded by the fact that the model cannot step in the direction of a more reasonable set of conventional technologies. The conventional technologies could be viewed as a single technology that proportionately serves the different load classes. Because the renewable market penetrations are computed somewhat exogenously, the model has very little flexibility with which to change the operating levels of different technologies.

Storage

Storage requires temporal and cost information that is not easily obtained or approximated in a simplistic model such as REP. It would seem as though storage would have to be handled as hybrid renewable storage technologies in the REP model. The contribution could be approximated in the same way as existing renewables, as approximate contributions to peaking, intermediate and baseload energies. If storage becomes important to the attractiveness of renewables, then these hybrid modeling methods will have to be investigated. The lack of storage capabilities in the model will bias against intermittent renewables.

Transmission

REP uses a creative and conceptually attractive approach to transmission, which is a very complex problem. The simulations look reasonable and appear to be consistent with areas where there are good data such as California. The assumptions could use a more thorough examination at some point.

Finances

A great strength of this model is that it incorporates technological and financial risks. Models which do not include these risks are likely to miss the main issue involved in the selection of renewables. Riskless models will overestimate the use of renewables, and so the REP model potentially has much greater accuracy in this area. A better calibration and explanation of the risk variables (economic attractiveness ratio, financial acceptance relationship, and gamma) would be helpful. It appears that the REP model results are in real dollars (while the TFRM results are in nominal dollars) but this requires further checking into the dollars and the accounting.

Environmental Concerns

The major policy mechanisms to be tested here are the carbon tax possibilities, and the REP model has shown success in the sensitivities examined by the panel. The panel has some concern about some of the insensitivities of renewable capacities to carbon taxes. This may be due to the renewables already being limited by manufacturing or other constraints. Flagging these constraints, when they are limiting, would be helpful to the user.

Usability

To the extent that the future for conventional technologies is known, and to the extent that the operator is aware and furnished with good input information, the REP model will be on solid ground. To the extent that the REP model is operating outside the areas of conventional wisdom, it becomes extremely important to feed this model with insights from more detailed models, from Energy Information Administration, the industry, or as envisioned by project initiators, from a model such as the Sandia National Laboratories Ten Federal Region Model.

There are two things that are needed for this model to provide important insights. (1) It must have excellent support data and a knowledgeable user and (2) It must run in minutes, rather than hours, or days. This turn-around speed is needed so that the user can make many sensitivity runs to become familiar with the area of the policy space being investigated. Until computer capabilities increase, therefore, the urge to add more complexity to the model must be carefully tempered by consideration of the additional computing capability required.

SUGGESTED MODEL IMPROVEMENTS AND ENHANCEMENTS

With the operating levels so tightly constrained, small movements should be watched as signs of needed changes in operating and capacity assumptions. It is probably entirely appropriate for this kind of national screening model to avoid complex areas such as choosing mixes of conventional technologies. It is, however, necessary that the operator be aware of pressures and strains within the model. For this reason, it seems *very important that the model output routinely print capacity factors (or percentage operating levels), cost of electricity, and other outputs that will make it easier for the user to make exogenous feedbacks* (such as yearly reporting of peak load, energy demand, all costs, installed resources, reserve margin, carbon, sulfur, technology mixes, and perhaps some jobs forecasts which are of major interest to much of the policy community).

Other kinds of back-end diagnostics would also be very helpful in guiding the user into comfortable areas. One of these that is important, and probably not too difficult, is to have *the model flag the constraints that are limiting.*

In addition to back-end improvements, an area of moderate cost and high potential payoff would be the addition of a front-end to the model that would *make it more user-friendly as well as increase the user understanding of the model workings.* It is almost always worthwhile to have a new programmer, specializing in foolproofing and user aids, spend the startup time to make the model more useable. Formats, menus, defaults, and other helpful devices would help make this model more accessible to analysts. A more complete and succinct disclosure of assumptions, inputs, valid application areas, limitations and concerns should be part of a user's guide or part of the automated front-end information.

The model requires that the user determine the capacity credit for renewables in each load class by out-of-model testing of the supply from that renewable against the typical regional load. The problem is that within a region there is strong correlation of the supply of solar, and to some extent wind energy. Multiplying the peaking capabilities of one unit by a whole region full of those units has the potential for greatly overstating the peaking capabilities of those renewables. *A method should be devised for changing these regional load-meeting credits based upon the extent of the use of the renewable resource.* The overall treatment of reliability in the model, as with TFRM, would benefit from improved calibration to actual loss-of-load-probability (LOLP) data and standardization of conceptual approach (if the models are to complement one another).

Another low-cost and potentially high-payoff project would be *the investigation of gamma (γ), and the calibration of the EAR/FAR mechanism.* There is a need to ensure there is not any double counting with the use of two non-knife-edge mechanisms. The user deserves more verification of the value of gamma than "no one has ever used anything different."

The REP model needs close support from a more detailed model, such as the Sandia TFRM, that can direct the mixes and capacity factors consistent with the opportunities available from renewables. It would also be very helpful to have such a model available to test the resource plans proposed by the REP model, to check mixes, costings, reliabilities, and other important performance measures. The use of these models in tandem is discussed in the documentation, but the Sandia TFRM is not user-friendly enough at present to offer as a viable partner to the REP model.[7] The panel knows of no other potential support model that has the renewables capabilities of the TFRM, thus the optimal use of the REP model is somewhat tied to the usability of the TFRM or the development of a similar model.

The REP model is missing several important feedback mechanisms, which, if incorporated, would destroy the necessary quick and simple nature of the model. One of these important feedbacks is the effect of the cost of electricity on the demand. A helpful addition here might be to use *a post-processor to generate the demands that would be consistent with costs of electricity in various years*. The user could then immediately see if changes in demand inputs were necessary, especially if input demands and cost-consistent demands were printed side-by-side.

Storage capabilities should be testable within the model. This may mean that *renewable-storage hybrids be tested, as well as conventional-storage hybrids*. These hybrids would have to be characterized with storage inefficiencies imbedded, and would have to be tuned to the needs of the region. There arises the same danger of overstating the peaking capabilities of renewable-storage hybrids when they are correlated within a region as previously described.

Chapter 2
DEMAND AND LOAD

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GLOBAL PERSPECTIVE

Forecasting customer load is the first of the three analysis steps in utility planning described in the capacity expansion section (see Chapter 3). This first step appears straightforward, but has many complexities that can trip up the analyst. Because the inability to store electricity requires that the power system meet both energy and capacity requirements, it has been traditional in the industry that both components of future loads be forecasted. Both forecasts are typically made on a ground-up approach: predicted numbers of customers, sizes of various component demands, etc., are inflated to the system level and converted into bus bar loads that the utility's assets must meet.

However, any sort of detailed production costing requires simulation of actual operations through time, usually on an hourly basis. The peak and energy forecast is, therefore, usually converted to an hour-by-hour load forecast by the adjustment of loads from an historic year that is considered in some sense typical, especially weatherwise. The peak and energy forecast defines the load factor of the system but provides no more detail on how hourly load shapes should be adjusted through time, which means most models use various heuristics to shape future loads into compliance with the forecast. One of the problems with this approach is that assumptions used in the formation of the load forecast are the least likely of all modeling assumptions to be questioned later by sensitivity analyses. Therefore, some quite questionable assumptions about future load shapes are often buried deep in data bases and never revisited. Since capacity expansion results can be quite sensitive to unit capacity factors, which directly depend on load shapes, results can be affected.

Once the customer load has been defined, the system has to be operated to meet that demand. For all but the short time-horizon-simulation, that is, less than one year, a full simulation of system operations for every hour of the year is neither feasible nor desirable. Rather, information in the load curve must be condensed into a reduced and more manageable form. Herein lies one of the great schisms in the industry between those models that reorder the loads into a load duration curve (LDC) representation and those that represent the year with short representative periods of sequential data. The later models are usually called chronological. The LDC approach permits the use of computationally efficient algorithms that approximate system operations, as are described by Sandia in the TFRM manual, while the chronological models can claim to better represent real world operational problems.[8] The magnitude of the problem at hand here precludes any load characterization beyond the simplest level. Therefore, a load duration curve approach is the most detailed analysis possible.

DEMAND AND LOAD IN REP

The REP model uses no representation of load in the conventional sense. The forecast of annual peak demand and total annual energy only serves to determine the pie to be sliced among technologies. It lies, therefore, outside the normal bounds of production costing.

Results

Simulation Results. PERI ran low and high demand cases as sensitivity analyses (see Appendix B). As with other results from the PERI model, the credibility of the results is limited by the fixed capacity factors of technologies seen in the results. For example, in all three test cases, 1 percent, 2.5 percent, and 4 percent demand growth, the capacity factor for coal generation is 65 percent in both 1995 and 2030. The capacity factor for gas-combined cycle falls from 57 percent in 1995 to 41 percent in 2030, but these numbers remain the same across all test cases, and the results for gas-combustion turbine are similar. In fact, it seems that capacity factors are driven by exogenous user inputs. Given the importance of capacity factor in determining the relative economic attractiveness of technologies, the ability of the REP model to simulate the consequences of dramatically different demand forecasts seems limited.

Usability. The model documentation of load characterization and demand forecasting is poor.

Recommendations. The capacity factors of assets should be reported so the user is alerted to the insensitivity of the REP model to changing load shapes. Better documentation of the role of demand in the model is required. The inclusion of an elasticity loop to reflect the effect of increasing customer costs on demand would be a useful feature.

Chapter 3
CAPACITY EXPANSION

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GLOBAL PERSPECTIVE

At the simplest level, the problem of electric utility planning can be reduced to three steps: (1) forecasting customer demand, (2) operating existing assets to meet current load through time, and (3) constructing or contracting for new capacity additions to meet future needs. Historically, the first and third steps have been linked; however, the process of deciding what type and how much new generating resources to buy or construct, and when and where to add them within a given electric utility system, was somewhat divorced from step (2), current company operations. Capacity expansion plans were developed using crude linearized approximation tools and intuition that overlooked the fact that the value of new additions is determined in part by the nature of the preexisting capacity in place, that the interaction between new and old capacity is complex, and that upgrading the preexisting capacity is a common approach to system improvement. That the simplicity of the planning did not tie the hands of future operators was more or less a fortuitous result of the predictable demand growth, the homogeneity of the mostly thermal generation being constructed, and persistent economies of scale that mitigated the burden of overbuilding.

The nuclear difficulties of the 1970s, the exhaustion of economies of scale in thermal generation, and the recognized need to better account for the special characteristics of non-thermal resources, such as renewables, prompted the development of improved planning methods that could integrate the three steps above into one unified process. The problem immediately encountered, namely the high computing cost of planning models, still dominates work in this area today. That problem, simply stated, is that enormous computing power is needed to repeatedly simulate system operations for the long planning periods necessary in an industry in which investments can be in place for decades. The large computing requirement arises for the most part from the difficulty of storing electricity, which unlike other products cannot be produced in a smooth flow and kept on hand until demand clears the shelves. Rather, enough generating capacity must be available at all times to instantaneously serve the varying load. A conflict has, therefore, emerged between the desire to carry out the most accurate simulation possible of the system in question taking all of the effects of timing correctly into account and the need to develop many plans with long time horizons.

The EGEAS model developed by EPRI and later commercialized by Stone and Webster and the commercial product of Energy Management Associates, PROSCREEN II®, are two commonly used models in the industry that solve the planning problem in some detail using dynamic programming expansion algorithms linked to a simplified Booth-Baleriaux equivalent load duration curve production costing. This combination represents more or less the limit of current computing capability at reasonable cost, and such a combination would certainly be impossible at the regional level.

Dynamic programming solves future additions in a stepwise annual progression that finds the optimal expansion path in terms of minimum net present cost of revenue requirements. Most importantly, dynamic programming provides a mixed integer solution, which in this application simply means that units added to the system are whole practical sized units and not idealized fractions. This distinction is important because the trade-off between the ability to absorb large, lumpy capacity additions and economies of scale was a recurring problem to the industry.

The models currently under review here, then, add to a long and rich history of research and practice of electric utility capacity expansion planning. The models' authors encounter the same conflict between computing requirements and accuracy, and with a particular vengeance, because the systems under review extend to the regional level and because particular attention is focused on the renewables that have been dealt with poorly in the past.

The extension of capacity expansion planning to the regional level represents a major departure from industry traditions. The only precedents for regional level capacity expansion planning are reliability planning done for the NERC regions and planning at the power pool level. The additional problems involved in planning regionally are as follows:

(1) Industry structure is heterogeneous. It is somewhat inaccurate to assume that a regional investor-owned utility exists and that planning for the region can be based on the same principles as might be used by a single company. In areas where locally controlled municipal utilities or larger government entities are major generators, inaccuracies would be the most severe. Notably, the lower costs of debt of these institutions is likely to skew technology selection in favor of higher capital cost options.[9]

(2) In addition to industry heterogeneity, creeping deregulation is leading to a growing share of generation going to independent generators whose decision making is based on project finance and differs significantly from investor-owned equity financing.

(3) Localized constraints within service territories can be quite important in determining utility decisions, and yet these concerns are lost at the local level. A key example is availability of sites.

(4) Utility dispatch is usually solved as a company-level problem. To the extent that the sum of individual utility dispatches differs from a hypothetical regional dispatch, modeling regionally can introduce substantial differences in results.

REP DESCRIPTION

The REP model does not follow in the tradition of capacity expansion models described above. Rather, the REP model is a technology adoption model that focuses directly on the attractiveness of renewables to utilities, bypassing almost entirely the trivia of systems operations. The competition between technologies is based on a straightforward economic test, which incorporates a risk adjustment and tax credits. The market for new utility capacity is segmented into fuel saver, peaking, intermediate, and baseload segments. As discussed above, a regional approach implies certain inaccuracies.

The fuel saver market provides an opportunity for non-dispatchable renewables to compete on a significant scale. The total size of the market is input by the user, and renewable technology and conventional technology compete directly within this market. A renewable can displace conventional generation if marginal generating costs of an existing conventional exceeds the total levelized energy cost of the renewable. If renewables reach their specified limit, (the default value is 10 percent) then the full market is allocated based on comparative financial attractiveness. Careful consideration is given to the declining productivity of renewables sites, and iteration sets the marginal productivity of each renewable resource. The total contribution of renewables is limited by maximum and minimum annual installation limits and a maximum rate of increase in installations. The capacity credit for the renewable capacity is calculated outside the model.

Dispatchable renewables do not compete in the peaking market, but compete directly in the intermediate and baseload markets. Here the competition is for new capacity additions only and selection is based on full life cycle costs.

Results

Results of the test cases show occasional sensitivity to the changed input parameters, such as the increase of 24 percent in installed gas-combined cycle capacity in 2030 that results from lowering the rate of gas price increases from 3 percent to 1 percent. However, in other instances, results are perverse. For example, increasing the cost of capital from 6.5 percent to 10 percent results in a slight drop in installed combined cycle turbine capacity in 2030. This result is most likely a consequence of the segregation of combined cycle turbines into the peaking market, which is limited in size.

Usability

The model is a large Lotus spreadsheet. Spreadsheet analysis tools have advantages and disadvantages for this type of analysis. The input and output is user-friendly and familiar to anyone who has ever used a spreadsheet. This makes adaption of the model possible for relatively inexperienced users, an obvious plus. On the other hand, spreadsheet models can be notoriously difficult to unravel and debug, and beyond a certain point they become unmanageable for serious analysis. Models written in traditional programming languages are more impenetrable to the user but are more easily and reliably improved by a programmer.

Recommendations

The approach of PERI to finding fast solutions to a problem that contains many imponderables, such as the ability of renewable supply industries to mature, is straightforward and reasonable. PERI took an intractable problem and solved it with common sense and modeling tools simple enough to be understood by the user. This is a considerable achievement.

However, the limitations of the model's capacity expansion planning are serious. The total absence of any production costing makes the capacity expansion results difficult to believe. The segregation of technologies into fixed roles apparently undercuts the sensitivity of the model to varying parameters. For example, in the low gas price test case, the capacity factors on gas-fired generation are virtually identical to the base case. As noted in Chapter 2, the inability of the model to endogenously estimate expected capacity factors on alternative resources weakens the entire analysis. Even the most rudimentary of economic analysis should consider the effect of capacity factors on the economics of project development. The focus of the modelers on the competition between renewable technologies and conventional technologies is reasonable given their objectives. However, to retain reasonable results when one departs from the conventional wisdom of the future requires consideration of competition among conventional technologies as well.

Other recommendations:

(1) Dispatch needs to be approximated by the adjustment of capacity factors for each technology, or through some other means. Duty cycles can change considerably over the long time horizons used by the REP model and key parameters cannot reasonably remain fixed.

(2) Output data need to show when the penetration of a technology has risen freely to its limit and when it has been limited by one of the constraints on market penetration.

Chapter 4
DISPATCH AND PRODUCTION COSTING

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MODEL DESCRIPTION

The REP model assumes capacity factors when it makes the decision to build new capacity. This is computed based upon a comparison of life-cycle capital and operating costs per unit of energy output. The values for peak, intermediate and baseload types are input as percentages in cell A66 as "application load factors."[10] These values are then apparently adjusted slightly to make the peak, intermediate, and baseload energy requirements come out as needed in the given years.

The REP model chooses and dispatches renewable energy options based upon a pre-processor estimate of the market penetration of each option. This estimate is made using a comparison of cost of electricity from other renewable energy options "relative to the marginal cost of displaced generations."[11] Renewables are assumed to compete in the intermediate and baseload markets. They can be credited, and this must be done exogenously, to the peaking, intermediate, and baseload areas. This is supposedly accomplished in out-of-model checks of the contributions that various renewables make in the different regions.

An equivalent dispatchable capacity rate is computed for each intermittent renewable energy class by a DOS or BASIC pre-processor computation of the equivalent capacity for the same loss-of-load-probability.[12] The costing in the REP model includes regionally adjusted capital costs, regionally adjusted fixed and variable operating costs, fixed charges, capital recovery factors, capacity and production tax credits, and present value of major maintenance.[13]

SENSITIVITY RUNS

The first result that seems to be a problem in the sensitivity runs had to do with carbon taxes (see Table 4.1). In every case, the carbon taxes generated more revenue than the extra amount that the electric customers paid. This means that the model has come to a better optimum with the carbon tax, just by pretending there is a tax, but not charging the tax. Unraveling this contradiction leads the analyst to the conclusion that the model has been constrained away from a more optimal area. This was apparently done both in setting the end mix of conventional technologies, and in the operating decisions that the model makes. This reveals how tightly constrained the model can be.

Table 4.1 Sensitivity Studies for Years 2015 and 2030

Case Study	Costs in Billions of Dollars: Capital Total	Capital Net	Total Carbon Tax	Operating Energy in MGWhrs: Total	Net	Carbon Emissions in Metric Tons C: Total	Net
Baseline							
2015	351	0	0	5.6	0.0	1010	0
2030	660	0	0	7.9	0.0	1566	0
Surprise Carbon Tax							
$25/ton							
2015	368	17	25	5.6	0.0	1004	-6
2030	690	30	39	7.9	0.0	1553	-13
$200/ton							
2015	483	132	198	5.5	-0.1	992	-18
2030	905	245	301	7.8	-0.1	1504	-62
Changes in Annual Demand Growth Rate							
2.5% to 1%							
2015	230	-121	0	3.8	-1.8	712	-298
2030	343	-317	0	4.4	-3.5	840	-726
2.5% to 4%							
2015	522	171	0	8.1	2.5	1422	412
2030	1226	566	0	14.0	6.1	2787	1221

Note: See Appendix B for definitions of case studies

It appears from some of the sensitivity runs performed by the modelers that the gas turbines do not change, even with changes in relative fuel prices. In the sensitivity runs examined by the panel, the reason for this is apparently that the gas turbines are the only competing technology in the peaking class. It is, however, possible to include storage and other peaking technologies.

In some of the other sensitivity runs, renewables are competing strongly with gas turbines, and gas turbine capacity factors go down significantly with this competition. In the comparison of the standardized base case, the REP model had 11 GW of gas in 2030, while the TFRM had 43 GW of gas. The fuel-saver displacement in the REP model of gas turbines by renewables is apparently responsible for this difference.

Another major difference between the REP model and the TFRM test case results was in wind capacity. The REP model had 13 GW of wind in 2030 while the TFRM had 87 GW. This was apparently caused by a miscommunication in the setup of the build constraints between the two models. This underscores the need for good input data, the need for sensitivity studies, and the need for flagging the important constraints.

There are some additional results in the Table 4.2 that seem to be counterintuitive. For example, the amount of wind capacity is lower in certain years when a $.015/kWhr tax credit for wind energy is added. This is explained by the fact that the better sites are taken earlier with inferior technology in the tax credit case; the model has performed very well in capturing this result.

Table 4.2 Sensitivity Studies for Years 2015 and 2030: Additional Results

	KGWhs				
Case Study	Wind	Photo-voltaic	Solar Thermal	Biomass Total	Geo-thermal
Baseline					
2015	264	0	0	113	106
2030	352	7	30	199	164
Surprise Carbon Tax					
$25/ton					
2015	265	1	3	117	116
2030	351	7	32	207	172
$200/ton					
2015	264	6	6	135	138
2030	351	21	45	242	138
Changes in Annual Demand Growth Rate					
2.5% to 1%					
2015	204	0	1	95	66
2030	231	1	12	123	122
2.5% to 4%					
2015	344	0	4	148	145
2030	545	23	63	481	180

Note: See Appendix B for definitions of case studies

Some other strange results have not been explained so easily without additional sensitivity studies. One such result has the amount of geothermal energy going down with the tax of $200 per ton carbon; one would expect geothermal to go up in this case. One explanation could be that the technologies that compete with the carbon emitters cover up some of the slim opportunity for geothermal. Another explanation could be that the 138 kGwhr of geothermal in 2030 being the same as the 138 in the year 2015 was just a printout or setup error. All of these numbers seem to be reasonable. The constraints are not as obvious in the operating results as they are in the capacity results.

CONCLUSIONS

The dispatch logic of the REP model is non-traditional, but it probably would be difficult to improve dispatch approximation within the framework of the model. This model, then, has only a very small amount of endogenous dispatching decision-making capability. This inability is somewhat compounded by the fact that the model cannot step in the direction of a more reasonable set of conventional technologies. The reason for this is that the end of period mix of conventional technologies that will serve the peak, intermediate, and baseload demand must be preset.[14] The conventional technologies will thus rise and fall in the same mix, as demands for them rise and fall. Conventional technologies could be viewed as a single technology that proportionately serves the different load classes. This, when combined with somewhat exogenous computation of renewable market penetrations, results in a model that has very little flexibility with which to change the operating levels of different technologies.

When the operating levels are so tightly constrained, small movements need to be watched as signs of needed adjustments in operating and capacity assumptions. It is probably entirely appropriate for this kind of national screening model to avoid complex areas such as choosing mixes of conventional technologies. It is, however, necessary that the operator be aware of pressures and strains within the model. For this reason, it seems very important that the model output routinely print capacity factors (or percentage operating levels), cost of electricity, and other outputs that will make it easier for the user to make exogenous feedbacks. The model assumptions seem to favor renewables over turbines. However, it is difficult to unravel any such bias without several model runs and flagging of constrained results.

To the extent that the future for conventional technologies is known, and to the extent that the operator is aware and furnished with good input information, the REP model will be on solid ground. To the extent that the REP model is operating outside the areas of conventional wisdom, it becomes extremely important to feed this model with insights from more detailed models, from EIA, the industry, or as envisioned by project initiators, from a model such as the Sandia National Laboratories TFRM.

There are two things that are needed so that this model will provide important insights. (1) It must have excellent support data, and a knowledgeable user and (2) it must run in minutes, rather than hours, or days. This turn-around speed is needed so that the user can make many sensitivity runs to become familiar with the area of the policy space being investigated. Until computer capabilities increase, therefore, the urge to add more complexity to the model must be carefully weighed against the costs of increased computing time.

Chapter 5
RELIABILITY

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RELIABILITY PLANNING PRACTICES AT ELECTRIC UTILITIES

Historically, reliability planning criteria were based on engineering judgment, with the earliest criteria being deterministically based. For example, the percent reserve margin approach is the earliest and most easily computed criterion.[15] This criterion is calculated by comparing the total installed capacity at the peak load period to the peak load. Electric resource planners have used figures ranging from approximately 12 percent to 25 percent as acceptable reserve margins for planning. These rule of thumb based percentages varied from system to system depending on the characteristics of the system and the planner's and operator's experience with the dependability of the system. The disadvantage of such an approach is that it is insensitive to unit size considerations, unit forced outage rates, and factors such as load shape. A variation of this approach was also used to capture the unit size impact on reliability. This approach, referred to as "loss-of-the-largest-generating-unit method," captured the effect in the reserve margin calculation of the impact of a single unit (or sometimes 2-units combined) outage contingency by adding reserves on top of the baseline reserve target, calculated as a percent of the largest contingency compared to the peak load. This approach, while an improvement, still did not address the issues of multiple unit outages, load shapes, and forced outage rates.

Probabilistic reserve criteria were subsequently developed based on the evaluation of the "loss-of-load-probability" (LOLP) index and expected unserved energy (EUE). A commonly used yardstick in the industry today is the 1 day in 10 years LOLP. LOLP is defined as the probability that the system reserve random variable (system capacity minus load) is less than zero. EUE is basically the expected energy demand that the system capacity is unable to serve due to loss of load events. LOLP, the more commonly used measure, considers forced outage rate characteristics and size of units, multiple unit outages, and load shapes. Thus, it has substantial improvements over the more traditional deterministic methods cited above. Although often cited as a way of standardizing or comparing the reliability of power systems, LOLP can be calculated using hourly loads or daily peaks and will give different equivalent reserve margin results using each method. Another characteristic of LOLP is that the particular index used (e.g., 1 day in 10 years, 1 day in 2 years, 1 day in 50 years, etc.) still is based on the planner's and operator's judgment. Thus, the planners for systems with the same characteristics and same reliability may employ different LOLP criteria based on their judgment as to the level needed for reliable service.

Most recently, the concept of value of service based reliability is increasingly being employed at utilities. This methodology is an extension of LOLP and EUE methodologies that integrates the costs of providing a particular level of service reliability with the determination of reliability worth from the customer's point of view. This approach is critical for determining an optimal reserve margin that minimizes total costs. As a methodology, it embodies all of the attributes of the probalistic methods and has the added advantage of capturing the worth of reliability from the perspective of the customer.[16]

RELIABILITY PLANNING METHODOLOGY EMPLOYED IN REP

PERI developed the REP model as a Lotus-spreadsheet model to perform "what if" types of analysis for renewable energy policy makers. The REP model does not directly calculate a required reserve margin for capacity expansion. Instead, it relies on external inputs for estimates of total potential market for intermittent technologies and for dispatchable technologies. The total potential market for intermittent technologies is defined as the energy production of the installed generating base. This is because for intermittents the opportunity for saving energy is by displacing conventional fuel. For dispatchable technologies, the total potential market is defined as new or retrofit generating plant additions.

The Electric Power Research Institute's Regional Systems Database (ERS-1) is the source for utility load profile information. These data were available on the basis of six regions, and were modified to represent the ten federal regions.

The off-line LOLP analysis used by PERI is roughly based on L.L. Garver's simplified graphical approach.[17] The Load Carrying Capability (LCC) that can be attributed to wind and other types of intermittent generators was calculated as the amount of conventional generation that would accomplish the same reduction in utility LOLP as the given amount of intermittents. As a result, wind and other intermittents are treated credited with capacity value even though they are primarily as displacers of conventionally fueled resources. This, in turn, reduces the perceived need for dispatchable capacity to meet reliability targets.

COMMENTS

PERI's conceptual approach to reliability for intermittent resources appears to be an improvement over approaches that either assume full capacity credit or no capacity credit for intermittent resources (such as wind). However, in application, the capacity credit for wind was not determined on a regional basis. Instead, a capacity value, approximately equal to its capacity factor, was used as a surrogate value for all ten regions. The principle weaknesses of this approach are the need to do reliability planning off-line and the use of an approximation method that is likely to introduce a substantial amount of cumulative error in long term capacity expansion plans.

PERI's approach of restricting the intermittents to displacing fuel from conventional technologies is a reasonable approach. Examination of the base case results show wind making up 6.7 percent (for capacity) and 3.9 percent (for energy) of the resource mix in the year 2030. These results appear realistic from a system operations perspective.

CONCLUSION AND RECOMMENDATION

PERI's approach to reliability planning appears to produce reasonable resource expansion plans. However, the potential for substantial cumulative error in developing the resource expansion plans is great, considering the long time frames being examined. It is recommended that the following study be undertaken: test the built out resource plans from this model against a detailed production simulation model and a detailed LOLP model.

Chapter 6
TREATMENT OF RENEWABLES AND POLICY ISSUES

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GLOBAL PERSPECTIVE

Incorporating renewable energy technologies (RETs) into utility planning and operations raises a variety of issues, including: (1) the availability of the renewable resource; (2) the cost and performance of the RET and the potential to reduce its cost over time; (3) the dispatchability of the RET; (4) the transmission and distribution impacts of the RET; and (5) the impact of various policy instruments on market penetration by RETs.

Resources

Renewable energy resources vary widely across the United States. Overall, wind resources are greatest in the belt from North Dakota to Texas and scattered mountain or coastal areas in the West and East; biomass resources are greatest across the eastern half of the United States and parts of the West; geothermal resources are primarily limited to particular locations in the west; hydro resources are largely in the West, but face increasing environmental constraints; and solar resources are widely available but best across the Southwest. Some of these resources are highly site dependent and variable.

Cost and Performance

The cost and performance of several RETs dropped sharply during the past 10-15 years. Wind electricity costs, for example, dropped by more than a factor of ten. Continuing technological advances for these and other RETs (such as biomass) will further reduce costs. At least as important for future cost reductions is realizing manufacturing economies of scale and learning.

Dispatchability

Geothermal is operated as baseload, biomass and hydro are dispatchable, and wind and solar are intermittent. Use of intermittent resources can offset fuel use by conventional generating technologies; intermittent renewable energy may also offset capacity, depending on: (1) the match between the renewable resource and the local utility loads — such as solar matching summer air conditioning demands; (2) the level of intermittent renewable energy technology (IRET) penetration into the grid — high levels of penetration tend to saturate their potential capacity credit; (3) geographic diversity — gathering renewable energy over a large area may moderate local fluctuations (but may increase transmission and distribution (T&D)

requirements); (4) the correlation between different renewable energy resources — wind and solar, for example, may complement each other in some areas and help provide capacity value.

Transmission and Distribution

Renewables have mixed impacts on transmission and distribution (T&D) requirements. Renewables such as geothermal, biomass, solar thermal, and wind are generally relatively large installations (typically 10 to 100 MW or so) and are often located at a distance from populated areas. Consequently, these systems will often require long, high power T&D extensions to carry power to the utility grid. In contrast, small scale renewables such as PVs or dish-stirling can potentially be widely dispersed within the utility service area and may then be able to reduce peak loading within the T&D system.

POLICY TOOLS

A variety of policy instruments are in use or are being considered or discussed as means of encouraging market penetration by RETs. These include the following:

- Tax policy:
  - Accelerated depreciation
  - Investment tax credits
  - Energy production tax credits
  - Property taxes
  - Externality taxes

- Green policies:
  - Green pricing
  - Green competitive set-asides
  - Green rates-of-return to utility investors

- Miscellaneous policies

It would be useful to understand the impact of these and other policies on: RET capacity expansion, electricity generation, emissions, ratepayer costs, tax revenues, and other factors.

REP DESCRIPTION AND RECOMMENDATIONS

The REP model addresses each of the above considerations at varying levels. Dispatch and capacity expansion are discussed in chapters 3 and 4 of this report.

Resources

The REP model uses a good set of resource data and appears to parameterize them in a reasonable manner within the constraints of this spreadsheet format. The actual implementation of these data and formulas within the spreadsheet was not examined, however.

Cost and Performance

Cost and performance projections seem reasonable overall but appear to have been set independent of market growth. This ignores the potential for capturing economies of scale and learning. Future implementations might modify the current time driven cost and performance improvements with consideration of the cumulative production volume through a learning curve.

Dispatchability

Dispatch and capacity expansion are discussed elsewhere in this report. The approach taken for assigning capacity factors to intermittants appears reasonable but further work is needed to clarify the resource, regional, and market penetration level dependence of these capacity factors. This is important in the context of the current implementation of the grid limit and capacity credit.

T&D

T&D is discussed elsewhere in this report. Future implementations may want to consider the potential costs and benefits of the distributed utility concept in more detail.

Policy

The REP model can address a variety of policy issues, including depreciation schedules, investment tax credits, production tax credits, property taxes, externality taxes, green policies, and others. Access to these features is in some cases done through proxies, and documentation of these features is sometimes lacking. A front-end that allowed more direct and user friendly access to these features would be helpful.

Chapter 7
STORAGE

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MODEL DESCRIPTION

Central storage is a separate component of the model that "competes with dispatchable peaking applications."[18] Central storage may represent "pumped hydro, batteries, superconducting magnetic storage or compressed air."[19] The peaking market options are "combustion turbine and central storage."[20] "Combustion turbines are by far the dominant choice at present."[21] "Since Renewable Energy options are not competing in the peaking market, the model does not estimate the split between combustion turbines and storage. Rather, the estimated size of the peaking market is simply entered in the output table as the amount of conventional peaking capacity installed. For tracking purposes, it is assumed that combustion turbines are selected to meet all peaking capacity needs."[22]

Hybrid systems, such as solar or wind with pumped storage, "are not addressed directly by the model, but are de-linked into renewables and storage."[23] Even the hybrid systems, however, are downplayed in the REP model. To provide storage with renewables usually "would increase capital costs to uneconomic levels."[24] The use of storage to move conventional baseload into peakload is considered "not appropriate...to the renewable energy" calculations which are the intent of the model.[25]

Central storage options are characterized by total in-service capital costs, unit operating and maintenance costs (fixed and variable), average heatrate (supposedly of the supporting capacity), emission rate (supposedly of the supporting capacity), by-product creditor disposal costs, and design life in years.[26] Supposedly, the process efficiency would also be needed.

SENSITIVITY RUNS

There was no storage used in any of the model runs to which the panel had access. It was always listed as NA (Not Available).

CONCLUSIONS

There is some question that arises with the argument that on one hand storage is not important because it is too expensive, and on the other hand intermittent renewables are so cheap that they always operate. If renewables begin to lose their cost advantage over baseload, then storage will be necessary to move their energy to the peaking times.

Storage requires temporal and cost information that is not easily obtained or approximated in a simplistic model such as the REP model. It would seem as though storage would have to be handled as hybrid renewable storage technologies in the REP model. The contribution could be approximated in the same way as existing renewables, as approximate contributions to peaking, intermediate and baseload energies. If storage becomes important to the attractiveness of renewables, then these hybrid modeling methods will have to be investigated.

Chapter 8
TRANSMISSION

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MODEL DESCRIPTION

The REP model applies T&D cost and loss factors to each technology in the calculation of levelized cost. In reality, these cost and loss factors are quite specific to the geographical distribution of renewable resources and their relationship to the geography of the local electricity network. In practice, such calculations can be quite complex. Therefore some kind of approximation is necessary.

The REP model uses a very simple geometry to approximate the distribution of renewable energy and its relationship to the transmission network. Each region is assumed to be a circle with area equal to the actual area of the region. The load is assumed to be concentrated at the center of the circle, and has a geographic size proportional to the population density of the region. The model then uses the following formula to calculate T&D losses:

$$\textit{Trans. Losses} = \textit{Resource Consumed} * \frac{\sqrt{\textit{Area of Region}}}{\textit{Population Density} * \textit{Resource Area}} * c$$

where c = constant.

This formula increases the losses linearly as the amount of renewable resource in the region decreases. PERI says that the typical estimate of T&D losses resulting from this formula ranges from 0 to 20 percent.[27]

The cost of transmission and distribution capacity is estimated by applying the loss factor to a default constant (equal to $2000/kW or $1600/kW).[28] Applying these estimates to the range of typical losses results in T&D costs for renewable technology in the range of $0-$400/kW. These estimates are consistent with those developed in California.[29]

The REP model documentation states that these calculations are not applied to biomass or distributed photovoltaics alternatives, only to wind, geothermal, and other solar technologies.[30]

PERI tested the sensitivity of results to changes in the default constant which determines the T&D capacity cost (i.e. the loss factor was held constant). Test case one reduced the default constant to zero. Test case two increased it by a factor of 10 to $16,000/kW. Selected results are summarized in Table 8.1 below.

Table 8.1 Transmission and Distribution Cost Sensitivity (in GW of Capacity in Year 2030)

	GW of Capacity				
Case Study	Combined Cycle	Nuclear	Wind	Biomass WW/FC	Geo-thermal
Baseline	67.85	65.02	121.90	3.18	28.80
Test Case One	665.10	64.93	123.87	32.94	31.18
Test Case Two	718.84	70.88	102.61	37.40	20.47

The results are intuitively plausible. Test case one lowers T&D costs for wind, and geothermal and their market penetration increases modestly at the expense of combined cycle. Test case two increases the costs of wind and geothermal considerably with corresponding large decreases in their market share. Biomass, which is presumed to be unaffected, gains market penetration as does combined cycle and nuclear.

The REP model of T&D costs and losses will require further substantiation. It has a first-order plausibility in most respects, but many of its assumptions need more careful examination.

Chapter 9
FINANCIAL AND REGULATORY ISSUES

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MODEL DESCRIPTION

The REP model uses levelized constant dollar costs based on rate base regulation economics for investor-owned utilities to characterize the institutional setting in which costs are incurred, and to track scenario costs. Levelized costs include both capital related costs and operating costs. The mechanical procedures for performing these calculations are well known and reasonably standardized. The REP model documentation references the Electric Power Research Institute's Technical Assessment Guide (1991).[31] Regional and corporate variation in depreciation and tax accounting procedures are to be expected, but they are probably small effects.

There are two larger effects. One is the difference between investor-owned utilities (IOU) under ratebase regulation and publicly owned utilities (POU). The second is the difference between utility ownership and private power finance, or non-utility generator (NUG) ownership.

IOUs have a substantially higher cost of capital than POUs. This is due to the availability of tax-exempt financing for POUs and their all-debt capital structure, compared to the IOU requirement of common equity capital subject to income taxes and higher cost corporate debt. The difference in cost of capital can easily be 50 percent.[32] By modeling the capital cost component of levelized cost in the IOU framework, these models create an upward bias industry-wide. Approximately 75 percent of the electricity industry is represented by IOUs, so this is not a very large effect, but is important in some regions.

The difference between NUG and utility finance is probably more significant. NUGs use project finance structure in most cases. This means that there is no financial recourse to any corporate entity, and the projects must have positive cash flow when they begin to operate. There is probably not a large difference in the capital charges between a NUG project finance structure and the corporate framework. The NUGs probably have a slightly lower cost of capital than IOUs, but typically face larger amortization burdens. The cash flow implications of these differences result in approximately equal capital charges. There may be, however, a bigger difference in risk-bearing potential. The viability of project finance structures is very sensitive to revenue uncertainty. Because the amount of debt that projects can bear is limited by the fixed debt service obligations, uncertainty in revenue may mean that such financing will not he available. The principle uncertainty for renewable energy technologies at the financing stage is technology performance. Capital cost uncertainty is resolved before financing; in the REP model it is accounted for in the technology risk premium.

The REP model documentation refers to a fixed change rate (FCR) adjustment factor as a method of incorporating financing (and institutional) variations on the basic IOU framework.[33] The issues associated with NUG finance, however, would have to be accounted for separately.

The REP model documentation makes no reference to income taxes as a component of fixed charges associated with investment. This appears to be an oversight in the documentation; discussions with the model vendor indicate that income taxes are included in the calculation of fixed costs that underlie the levelized capital algorithm.

The REP model includes financial acceptance relationships (FAR) to incorporate financial risk. The FAR is a table which compares the ratio of levelized cost for renewable resources to conventionals and applies a scaling factor to the market acceptance decision. The values in this table are calibrated such that at equal cost the market is shared equally between the two technologies. When the renewable energy costs are less than conventional, their marker share increases above 50 percent (for example, it is 91 percent at an 85 percent ratio). Conversely, when renewable technologies are at a cost premium, their share is less than 50 percent (for example it is only 12 percent when the cost ratio is 1.25). In all cases, the REP model uses a risk-adjustment to the capital costs.

The conceptualization of the FAR is not sufficiently explicit to allow for a distinction between the behavior of IOUs and the NUG/project finance environment. Nonetheless, it captures in some respect the new technology risk associated with renewable technologies. It appears from the table in their December 7, 1993, report that the FAR only applies in the fuel saver market (e.g. wind and not biomass).[34] Furthermore, it is by no means clear how the values in the FAR were calibrated.

The REP model performed sensitivity runs on the FAR parameter. The tests consisted of changes in the shape of the curve from the hyperbolic function in the base case to two extreme linear cases. In test case one, market acceptance is zero whenever the renewable energy cost is equal or greater than the conventional alternative, and becomes 100 percent when renewable energy is less expensive. In test case two, by contrast, the linear relationship is stretched out so that 50/50 market share is achieved when costs are equal, zero occurs when renewable costs are twice those of conventional, and 100 percent when renewable costs are half those of conventional.

The results of these tests are more significant in the intermediate years than in the final years of the simulations; that is, changes in the FAR representation affect the timing of additions more than ultimate market share. This is illustrated for wind turbines in Table 9.1.

Taole 9.1 Wind Turbine
(Capacity in GW)

	Year			
Case Study	2000	2005	2010	2015
Baseline	14.20	61.50	79.90	91.40
Test Case One	2.00	7.20	41.10	94.30
Test Case Two	43.90	61.40	78.90	91.10

Test case one shows substantially lower market penetration for wind turbines in the years 2000 and 2005 than either the base case or the test case two. By 2010, however, a large increase occurs, followed by an even larger one in 2015. PERI argues that part of the large delayed effect in test case one results from the interaction of technology progress over the time period with the retarded early penetration; there is a more attractive resource left for new efficient technology in this case than in the other two.[35] Test case two shows much slower and more even market penetration than either test case one or the base case. The base case also has something of the "bang-bang" technology adoption logic illustrated in the extreme by test case one.

While these sensitivity tests are interesting and qualitatively plausible, the underlying issue of calibrating the FAR feature remains an issue for the REP model.

Chapter 10
ENVIRONMENTAL EFFECTS

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GLOBAL PERSPECTIVE

The inclusion of environmental effects in various production costing and utility planning models reaches one of three levels.

At the first level of implementation, the model does no more than keep track of estimated environmental insults. Emissions are usually based on simple emissions factors but a functional representation is often used for pollutants whose creation varies nonlinearly with output, such as NOX. Since production costing can be considered a simple accounting exercise in which the primary function of the model is to keep track of the numerous details of power system operations that must be taken into account in planning, environmental accounting readily fits into this general framework. The environmental consequences of utility operations are tracked along with the other effects. Most production-cost models today can at least estimate air emissions of SO_2, NOX, and VOC's, and often CO_2. Tracking of other environmental effects, such as land use, is less common.

At the second level, emissions are not only tracked, but are recognized as constraints on generation. The constraints have two common forms. The first is the capability to tax pollution, usually through the inclusion of a simple adder to generation costs. The second form attempts to replicate actual emissions regulations. For example, certain pollutants are subject to emissions ceilings, either within a geographical boundary or over a time period. These are real limits that change the way utilities operate and should be represented in models.

At the third level, models can be built that simulate operations under environmental as well as economic objectives, or under a combination of the two. Dispatch can be simulated as SO_2 emissions minimizing, for example. While such simulation may sound unrealistic, a total environmental dispatch capability is a useful tool in policy analysis where the question often being asked is, What is the maximum possible effect of this proposed policy instrument? The most commonly used production-cost model in the industry, PROMOD III®, a product of Energy Management Associates, incorporates such an environmental dispatch capability for the major air pollutants.

REP AND ENVIRONMENTAL EFFECTS

The REP model tracks emissions of the criteria air pollutants NOX, SO_2, and particulates and also total carbon at the first level described above, and REP successfully conducted the carbon tax case (see Appendix B).

Results

Simulations. The only emissions results reported by REP appear in the carbon tax test cases. In the $200/ton case, carbon tax revenues reach $300 billion by 2030 and yet total carbon emissions are only 4 percent lower, although installed capacity is 0.9 percent lower and generation 1 percent lower. This result shows remarkable insensitivity to the carbon tax, which increases total costs by a third. The share of coal generation in the mix of 2030 falls but by less than a percentage point, and the share of combined cycles falls by a greater amount.

Recommendations. The reporting of the REP model meets the basic standards of acceptability but the insensitivity of results in the carbon tax case is a cause of serious concern. The penetration of renewables could be understandably inhibited by special limits, such as resource availability. However, the penetration of gas-fired combined cycles should not be limited and the result that their penetration by 2030 is lower under a huge carbon tax is simply not credible. Furthermore, over the period that the tax is in place, the total installed coal capacity doubles. The problem may lie in the inability of the combined cycles to compete freely for the baseload with coal at high capacity factors.

The REP documentation needs to more fully explain the treatment of the carbon tax in their test cases, given that treatment of pollution taxes is a claimed capability of the model.[36]

APPENDIX A

Appendix A
COMMENTS ON MODEL TEST RESULTS AND COMPARATIVE RESULTS

Following is a commentary on the results from the specified scenarios and cases that were run with Sandia's TFRM and PERI's REP model.

SCENARIOS

Based on a quick examination of the results, each model by itself appears to be performing reasonably relative to the base case. For lower gas price forecasts, the amount of combined cycle and combined turbine (CT) installed generation increases, while coal and wind decrease in the Sandia model. In PERI's model, the changes in installed generation were rather muted. Installed coal resources decreased and combined cycle capacity increased, as expected. However, CT capacity remained essentially the same, and wind capacity increased slightly. I would have expected greater changes in installed capacity in PERI's model in response to the change in gas prices. For higher cost of capital, both models illustrate the impact on the higher capital cost plants by showing a reduction in coal, wind and solar, and slight increases in the installed capacity of combined cycle and CT generation.

A comparison of the results between models, however, raises some significant issues that need to be resolved before REP, for example, can work as a screening model for TFRM. The most significant issue is that each model builds out resource plans that differ by 30 percent or more in installed capacity. And, within a given case or scenario, the installed capacities of the technologies differ substantially. For energy generation, the differences are less than 5 percent, although the technologies vary substantially between the models.

Conclusion

The output of the Sandia TFRM appears responsive to changes in the key parameters of fuel price and capital cost. However, the response, as measured by changes in the resource mix, appears exaggerated. The output of PERI's REP model is also responsive but appears muted in its response. While time does not permit a detailed diagnostic to be run on the inter-model results, the results suggest that more development on the reliability/capacity expansion algorithms is warranted before these models can be relied upon to support policy development for renewable energy technologies. Unless the reliability and expansion algorithms are standardized for each model, the models are unlikely to complement each other.

POLICY RUNS

Both models responded reasonably to the specified policy runs for load growth sensitivity. It is unfortunate that cross model comparisons are not possible for these cases, since Sandia used

Region VI (Southwest) data and PERI appears to have used data that aggregated all 10 regions. For the high growth case, such a comparison might have further highlighted the need for a more standardized reliability and expansion algorithm to be used by each model.

With respect to policy runs on carbon taxes, Sandia's model appears to respond reasonably as measured by changes in the resource mix. Of continuing concern, however, is the absolute amount of intermittent resources (e.g., wind) included in the resource mix. The amount appears excessive when considered from a system operation and reliability perspective. PERI's model behaves similarly but does not have excessive amounts of intermittent resources in the mix. PERI also appears not to have constrained nuclear development, which increases in the high carbon tax scenario as expected.

MODEL-SPECIFIC RUNS

Sandia's model-specific runs were: (1) a solar accelerated-cost reduction case; (2) a storage competition case; (3) a 30 percent reduction in load variability case; and (4) a 30 percent increase in load variability case. Performance of the model appears reasonable for all cases with the continued exception of wind. The percentage of wind in the resource mix remains unreasonably high from a system operation perspective. However, this is not a criticism of the performance of the models under these model-specific runs.

PERI's model-specific runs were: (1) EAR/FAR tests;[36] (2) Risk Premium tests; (3) Grid Limit tests; (4) Transmission and Distribution Costs tests; (5) Manufacturing Capability tests; and (6) manufacturing scale economies for renewable energy technology equipment tests.

REP performed sensitivity runs on the FAR parameter. The tests consisted of changes in the shape of the curve from the hyperbolic function in the base case to two extreme linear cases. In test case one, market acceptance is zero whenever the renewable energy cost is equal or greater than the conventional alternative and becomes 100 percent when renewable energy is less expensive. In test case two, by contrast, the linear relationship is stretched out so that 50/50 market share is achieved when costs are equal, zero occurs when renewable costs are twice those of conventional, and 100 percent when renewable costs are half those of conventional.

The results of these tests are more significant in the intermediate years than in the final years of the simulations; that is, changes in the FAR representation affect the timing of additions more than ultimate market share. Test case one shows substantially lower market penetration for wind turbines in the years 2000 and 2005 than either the base case or the test case two. By 2010, however, a large increase occurs, followed by an even larger one in 2015. PERI argues that part of the large delayed effect in test case one results from the interaction of technology progress over the time period with the retarded early penetration; there are more attractive resources left for new efficient technology in this case than in the other two.[37] Test case two shows much slower and more even market penetration than either case one or the base case. The base case also has something of the bang bang technology adoption logic illustrated in the extreme by test case one.

APPENDIX B

Appendix B
TASK DESCRIPTION FOR RENEWABLE ENERGY MODEL REVIEW

The following describes the support work to be completed by Sandia National Laboratories (SNL) and Princeton Economic Research Inc. (PERI). These tasks fall into three basic areas:

(1) Standardized model runs to compare model compatibility

(2) Policy model runs to gauge model sensitivity to various policy variables

(3) Model specific runs to capture unique model attributes

Base case: unless otherwise stated, the base case is defined as 3 percent annual increase in the real price of oil and gas, 0 percent annual increase in the real price of coal, 6.1 percent cost of borrowing, 2.5 percent annual growth in demand, and the same efficiency improvements for RETs and conventionals.

STANDARDIZED MODEL RUNS

The standardized model runs are for the purpose of comparing the model output of the PERI and SNL models with each other. To the extent possible, the PERI and SNL runs must use identical assumptions, data, time periods, discount rate, and model features. Unless otherwise stated, this standardization will occur through discussions between SNL and PERI, and this standardization will be documented.

The model will compare three scenarios:

(1) Base case

(2) Reduction in oil and gas real price increase to 1 percent per annum (0 percent for coal)

(3) Increase in the cost of capital (cost of borrowing from 6.1 percent in the base case to 10 percent for scenario)

These three scenarios will be examined under the following restrictions:

(1) Simulation of Region VI data only (Southwest)

(2) Technologies limited to wind, solar thermal, biomass, photovoltaic (PV), coal, combined cycle, and gas turbine (assume nuclear capacity unchanged throughout scenario)

(3) Assume same efficiency improvements in conventionals and RETs during period of analysis

These results will be reported in the following format:

(1) Capacity and generation will be reported by technology by cumulative megawatts and gigawatt hours.

(2) Time period of analysis will be 1992 to 2030.

(3) To the extent possible, graphics will be used to report results (with data tab backups).

(4) If possible, report the constant dollar cost of capacity expansion and operation by technology.

The results of these model runs will be delivered to ORISE no later than December 8, 1993. ORISE will distribute the results to the panelists and DOE.

POLICY RUNS

The policy runs will not require the PERI and SNL models to standardize assumptions, parameters, etc., limit technologies, regions or other variables. These runs are to test the model sensitivity to various policy variables using the full power of the models.

The following two policy issues will be examined and compared to a base case (base case assumes zero carbon tax):

(1) Carbon tax: The carbon tax analysis will consist of four scenarios.[38] The key variables to be evaluated are ratepayer cost, cost to the Federal Government, and annual carbon emissions (in short tons). The four scenarios are:

A. Carbon tax $25 per ton carbon (C) in 2005 (no surprise)

B. Carbon tax $25 per ton C in 2005 (surprise)

C. Carbon tax $200 per ton C in 2005 (no surprise)

D. Carbon tax $200 per ton C in 2005 (surprise)

(2) Comparison to base case of assumptions that demand growth is A) 1 percent per annum, B) 4 percent per annum.

The reporting format will be the same as for the standardized model runs. Results are to be delivered to ORISE no later than December 15, 1993 for distribution to DOE and panelists.

MODEL-SPECIFIC RUNS: PERI

Using their judgement regarding data values and assumptions, PERI will examine the sensitivity of their model to the following variables:

EAR/FAR

risk premium

grid limit

transmission and distribution costs

manufacturing capacity for RET equipment (quantity)

manufacturing scale economies for RET equipment (cost)

In addition, PERI is invited to provide the panel with information regarding their model's "best trick," i.e., counterintuitive results that can be explained by model logic; innovative approaches to problems, etc.

There is no standard format for reporting the results of these runs; however, the results of the sensitivity analysis should be summarized for the panel (graphics with backup tabs preferred). Results are to be delivered to ORISE no later than December 15, 1993 for distribution to DOE and panelists.

MODEL-SPECIFIC RUNS: SANDIA

Using their judgment regarding data values and assumptions, Sandia will examine the sensitivity of their model to the following scenarios:

(1) Comparison runs with and without storage

(2) Comparison of changes in load duration curve:

  A. Leveling of load duration curve

  B. Accentuation of load duration curve variability

(3) Model sensitivity to changes in the capital costs of renewable energy technology

In addition, Sandia is invited to provide the panel with information regarding their model's "best trick," i.e., counterintuitive results that can be explained by model logic; innovative approaches to problems, etc.

There is no standard format for reporting the results of these runs; however the results of the above analysis should be summarized for the Panel (graphics with backup tabs preferred). Results are to be delivered to ORISE no later than December 15, 1993 for distribution to DOE and panelists.

APPENDIX C

Appendix C
Princeton Economic Research, Inc., Response to Evaluation of Tools for Renewable Energy Policy Analysis: The Renewable Energy Penetration Model

PERI has no major disagreements with the panel regarding its evaluation of the models, the capabilities, or performance. Our response, therefore, is an assessment of how we might implement the panel's recommendations for model improvements.

Some of the panel's suggestions dealt with the underlying assumption and methods used in the model, and how they affect the results. The model was intended as a simple and accessible companion to more complex modeling efforts, and the panel's assessment clearly shows they have taken these limitations into account. Most of the panel's suggestions, such as calibration of the Financial Acceptance Relationship, are achievable within the current framework of the model. However, as the panel has pointed out, any expansion of the model detracts from original objective of building a simple tool. PERI is committed to working with our client to improve the model while maintaining the original objectives of simplicity and transparency.

The panel also made suggestions for some changes in the model mechanics. Most of these would be fairly simple to implement. For example, it would be a relatively simple task to add flags to the model output to indicate where the penetration of renewables has been limited by available resources, manufacturing capabilities, or other constraints. We can also, with little effort, add COE figures and capacity factors to the model output, as well as reorganize the layout to make it easier to interpret.

However, retaining compatibility with Lotus 1-2-3 version 2.2 limits our ability to address a recurring comment in the evaluation; the need for a "user-friendly" model interface. While a macro-based menu system could be added, it would significantly increase the size and complexity of what are already large (>4 megabytes total) spreadsheets. One alternative would be to move calculations that are performed in the Market Analysis spreadsheet into an executable program (written in Basic, Fortran, or some other programming language) with a simple user interface. This approach has the advantage of providing a more structured programming environment for the calculations that make up the core of the model. The disadvantage would be the loss of some accessibility to the internal working of that part of the model.

A second alternative would be to use another spreadsheet program, such as Excel for Windows, which has better user interface features built in. With this approach, users would still have the ability to "look inside" the model, but they would also have to purchase copies of the new spreadsheet program to run the model. We will explore these options with our client, and try to come up with an improved interface.

ENDNOTES

1. Energy Information Administration, U.S. Department of Energy, *Annual Energy Outlook 1993 With Projections to 2010*, DOE/EIA-0383(93) (Washington, DC: U.S. Department of Energy, 1993), p. 4.

2. See Sandia National Laboratories Strategic Technologies, "Tools for Renewable Energy Policy Analysis" Draft Report SAND92-2558, 5 volumes, (Albuquerque, New Mexico: Sandia National Laboratories, 1993).

3. For detailed documentation, see Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume V.

4. EGEAS is the Electric Generation Expansion Analysis System which is a product of Stone and Webster, Inc.; PROVIEW® is a proprietary product of Energy Management Associates.

5. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume V. p. 1.

6. *Ibid*, p. 13.

7. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume I.

8. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume III, pp. 3-4.

9. Please see Chapter 9 for discussion of this point.

10. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume V, p. 10.

11. *Ibid*, p. 14.

12. *Ibid*, Appendix B.

13. *Ibid*, p. 26.

14. *Ibid*, p. 11.

15. See Harry G. Stoll, *Least-Cost Electric Utility Planning* (New York: John Wiley and Sons, 1989), p. 322.

16. See Sandra Burns and George Gross, "Value of Service Reliability" paper presented at the IEEE/Power Engineering Society meetings at Atlanta, Georgia in February 1990. This paper has been recommended and approved by the IEEE Power Systems Engineering Committee of the IEEE Power Engineering Society.

17. The LOLP calculation used a simplified method established by L.L. Garver in his paper, "Effective Load Carrying Capability of Generating Units," *IEEE Transactions on Power Apparatus and Systems*, (August 1966).

18. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis", volume V, p. 14.

19. *Ibid*, p. 15.

20. *Ibid*, p. 53.

21. *Ibid.*

22. *Ibid.*

23. *Ibid.*

24. *Ibid*, p. 52.

25. *Ibid.*

26. *Ibid*, p. 39.

27. Personal communication, January 4, 1994.

28. In Sandia National Laboratories "Tools for Renewable Energy Policy Analysis," volume V, p. 40, the default setting is $2000; in the personal communication of January 4, 1994 the default setting was $1600.

29. See Southern California Edison, "Transmission Cost Tables 1993."

30. Sandia National Laboratories "Tools for Renewable Energy Policy Analysis," volume V, p. 40.

31. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume V, p. 2.

32. Suppose the IOU had 50 percent equity and 50 percent debt in its capital structure, and that the cost of equity capital were 11 percent and the cost of debt were 8 percent. This would give a weighted cost of capital of 9.5 percent. The income taxes on common equity, both state and federal might be 40 percent, which would add 2.2 percent, for a total cost of 11.7 percent. By contrast tax-exempt bonds sold by POUs might cost 7 percent. If the IOU had less equity and more debt, the difference would be smaller.

33. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume V, p. 37.

34. See the section "Standardized Policy Runs" in Appendix B.

35. December 21, 1993 memorandum from Frank Brock and Tom Schweizer of Princeton Economic Research Inc., p. 6.

36. Sandia National Laboratories, "Tools for Renewable Energy Policy Analysis," volume V, p. 16 and p. 45.

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