Applications Guide: Distribution Capacity Planning With Distributed Resources

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REPORT SUMMARY

The purpose of this report is to describe the use of EPRI's Area Investment Strategy Model to determine whether distributed resources (DR) should be integrated into the least cost expansion plan for a utility's distribution planning area. The report is a guidebook that is designed to help users apply the model.

Background

Interest in distributed resources has been rekindled following research efforts begun by EPRI, PG&E, and NREL in 1992. As a result of that interest, many claims have been advanced for the beneficial consequences of the use of distributed resources. Some of the claims have been supported by questionable analysis, while other claims have been asserted with virtually no analytic support. Although no general statements can be made about distributed resources that are applicable to all planning areas, the Area Investment Strategy Model is shown to be a useful tool for answering the question of whether distributed resources ought to be applied in a particular situation.

This guidebook has six sections. The first section, an Introduction, defines the problem addressed by the model: the problem of distributed resources planning is to determine how best to integrate distributed resources into the capacity expansion plan for a local planning area. The analytic problem is to determine whether the least cost expansion plan for an area includes distributed resources.

The second section is a historical sketch and brief literature survey that discusses earlier methods applied to the DR planning problem. Section 3 describes the main ideas encountered in strategic planning for the distribution system, with particular attention to the role of distributed resources. The discussion is general and somewhat theoretical. Application oriented readers may wish to skim these sections and pass on to the more applied portions of the guidebook.

The next three sections are designed to teach the reader how to apply the methodology. Section 4 describes the methodology of the Area Investment Strategy Model in general terms. Section 5 is a tutorial on Area Investment Analysis supported by some hypothetical examples. It is important that the reader apply the model to these examples in order to gain experience in using the model. Section 6 describes the application of the model to two real utility examples. The second example illustrates in detail the use of the load uncertainty assessment software contained in the Area Investment Strategy Model.

Objective

The purpose of this research is to provide a method whereby utility planners can determine whether distributed resources should be applied in a local planning area.

Approach

The Area Investment Strategy Model is described and applied to various planning problems. Those examples illustrate some of the ways that distributed resources add value in planning areas.

Results

The main results of this study are as follows:

- The Area Investment Strategy Model can be used to determine whether distributed resources are valuable in an area.
- No general statements about the value of distributed resources are universally applicable.
- The value of distributed resources depends on local conditions, including load growth uncertainty.

EPRI Perspective

The notion of distributed resources has become an increasingly popular concept over the last ten years. Manufacturers and regulators are promoting the use of distributed resources in the distribution system. Distributed resources are being touted as the centerpiece of an new infrastructure strategy. The purpose of that strategy is to supplement and replace traditional distribution investments.

In developing this guidebook, EPRI's interest is in providing methodology. Utilities need a way of evaluating the competing claims. EPRI is not taking a position in support of DR or in opposition to DR. The idea appears to be interesting, but whether DR makes sense is an economic issue, assuming DR is technically feasible. EPRI is interested in providing the methodology for analyzing DR as part of the general problem of distribution system planning under uncertainty.

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ABSTRACT

This guidebook illustrates the use of the Area Investment Strategy Model in solving distribution planning area expansion problems under uncertainty. The model is uniquely capable of determining the value of distributed resources in local planning areas. The literature is reviewed and the model is contrasted with other approaches to the problem. The methodology is described. An investment analysis tutorial, which explores the fundamental ideas encountered in distribution planning is given. Three examples, two taken from actual practice, are extensively analyzed using the Area Investment Strategy Model. In particular, the use of the Load Assessor to describe the uncertainty in area peak load growth is illustrated.

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INTRODUCTION

The purpose of this guidebook is to present a new approach to distributed resources (DR) economic analysis and planning. The new approach is implemented in the EPRI Area Investment Strategy Model. The model is described in this guidebook, examples are presented, and an investment analysis tutorial is given below to provide readers of this guidebook and users of the model with a step-by-step approach to apply the model to actual situations.

Some parts of this guidebook set the context of the model and describe the problem of DR analysis in general economic or theoretical terms. These sections may be skipped without loss of ability to apply the model. Such sections are identified below.

The new approach to DR planning is guided by several fundamental considerations:

1. Distributed resource decisions are investment decisions. Thus, they are evaluated in the same way any investment alternative is evaluated.

2. Distributed resource decisions are based on local considerations. Therefore, global or "macro" assessments of the strategic value of distributed resources provide virtually no guidance about what should be done in a local planning area.

3. Distributed resources do not comprise a unique, pure strategy for meeting local demand. Instead, all distributed resource decisions are made with respect to the role that distributed resources play in an integrated local expansion investment plan. Hence, the strategic value of distributed resources is based on the degree to which their integration improves the performance of the plan.

4. The fundamental benefit of distributed resources is their ability to provide modular and flexible alternatives to large, so-called "lumpy," investments. This benefit arises partly because modular investments are able to follow load more closely. Perhaps the greatest value of distributed resources is their ability to serve as a hedge against uncertainty in load growth. Therefore, any method that attempts to guide the integration of distributed resources into local area investment strategy must address the issue of load growth uncertainty.

5. An important value provided by distributed resources is their ability to provide increased service reliability to local customers. Therefore, any method that attempts to guide the integration of distributed resources into local area investment strategy must address the issue of service reliability.

6. The fundamental requirement of an acceptable local expansion investment plan is to meet load with sufficient reliability at minimum cost. In particular, the objective of DR planning

is to determine how and whether distributed resources are included in the investment strategy that meets customers' capacity needs at the lowest expected future cost.

7. The economic analysis of DR resources is properly based on actual cash flows, including actual capital investments (lump sums or streams) and actual operating costs.

An immediate consequence of these considerations is that the value of distributed resources is greatest when the risks are greatest. DR investments permit planners to delay larger, less flexible capital commitments while the planners refine forecasts and learn more about the future conditions that may determine the best investments.

Further, these considerations suggest that DR investments are not appropriate in every situation. In the ideal case, DR investments may be used to delay infrastructure investments until the question of the need for those investments can be definitively answered. Nevertheless, it is almost surely incorrect to conclude that DR investments can delay infrastructure investments indefinitely in a cost-effective manner. Since the unit capital cost of infrastructure is at most one-third that of the cheapest DR investment (engines, which currently cost approximately $300/kW), the modularity of the DR investments is not worthwhile if the distributed resources must replace entirely the capacity of the avoided large infrastructure investment.

A natural question to ask is whether there are characteristics of a local planning area that determine whether DR has value in the area. This question has been studied in a related report that applied the Area Investment Strategy Model to the DR problem in general (Feinstein (1999)). The following considerations and conclusions are noted here since they can guide planners' explorations of DR planning.

Local planning areas may be broadly classified into those that are transmission constrained and those that are infrastructure constrained. A transmission constrained planning area has sufficient distribution infrastructure to meet foreseeable load growth, but is constrained by lack of transmission capacity. Increments to transmission capacity come in relatively large quantities and with attendant large capital cost. It is natural to expect that distributed resources will have value in such areas since the distributed resources can be used to meet increasing peak loads and thereby eliminate the necessity for system generation capacity to serve those loads. If that need is eliminated, then additional transmission capacity is not required. (The idea here is that new load must be served by some energy source. If that source is the bulk system, then the transmission capacity must be increased or upgraded. If that source is local, i.e., a distributed resource, then the transmission capacity need not be increased.) The main value of the distributed resources, then, is in deferring the transmission expense. This was the basis of the analysis of the effect of targeted DSM in the PG&E system. (Orans (1991), Feinstein (1997a)).

An infrastructure constrained area has sufficient transmission capacity to meet foreseeable load growth anywhere in the local area, but is constrained by lack of distribution system infrastructure, such as transmission substations and distribution feeders. Increments to distribution capacity come in somewhat smaller quantities and costs compared with transmission upgrades. Further, the capital cost of distribution infrastructure capacity is somewhat smaller than that of transmission. It is natural to expect that distributed resources will have value in such areas since the distributed resources can be used to meet increasing peak loads and thereby defer or eliminate the necessity for distribution capacity increments to serve the load. Furthermore, it may be expected that distributed resources will increase reliability, decrease pollution, or decrease operating costs and thus yield strategic value.

The main results of the study are as follows:

- Distributed resources are strategically valuable in local areas that are transmission constrained, but have limited strategic value in local areas that are infrastructure constrained.
- Unless distributed resources can become much less expensive in both operating and capital costs, the least cost expansion plans in an infrastructure constrained area are composed of traditional infrastructure investments like substations and feeders.
- The value of distributed resources decreases as the area peak load growth rate increases in areas that are either transmission constrained or infrastructure constrained.
- Distributed resources provide benefit by deferring the need for the traditional capacity investments and not by eliminating the need for the investments.

The objective of this guidebook is to introduce the reader to the essential DR business planning questions and issues. The underlying planning assumption is that DR can potentially help solve specific problems associated with meeting customer needs. A description of the current state-of-the-art approach for solving the economic problem of integrating DR into electric distribution systems is provided below. Before turning to that approach, we will discuss the benefits that are generally attributed to distributed resources. This section ends with a statement of the problem to be solved by the methods presented in this guidebook.

Overview of DR Benefits

DR investments provide two kinds of benefits. At a customer site DR can supply back-up generation and may even reduce or replace dependence on the local electric utility. In the distribution system, DR can be integrated into the electric power delivery to provide capacity and, in the case of generation and storage technologies, energy.

Analysis of customer-site benefits is a straightforward engineering-economic problem. For customer-site analysis methods, we refer the reader to utility in-house engineering-economic manuals and to EPRI's Capital Budgeting Notebook (TR-104369). The problem addressed at a specific customer site is to determine the least cost alternative for meeting specific customer needs. For example, if a customer demands back-up generation, the planning problem involves finding the least cost way of providing the generation, and determining if the customer is willing to pay the cost of the specific back-up service. Customer-site analysis tasks are not systems problems and the solutions tend not to be driven by uncertainties due to future load growth and costs.

Determining whether DR should be part of the energy delivery system is a much more difficult business planning question. Electric distribution systems are complex. They are composed of many interrelated components including transformers, feeders, relays, switches and capacitors. This makes the future value of such components dependent on future load growth and the uncertainties associated with this growth. This creates risk and the need for risk management.

Therefore, a fundamental question is whether the risk management benefits provided by distributed resources are worth the additional costs of those resources.

Problem Statement

The problem of distributed resources planning is to determine how best to integrate distributed resources into the capacity expansion plan for a local planning area. The analytic problem is to determine whether the least cost expansion plan for an area includes distributed resources.

Clearly, this problem is solved by a method that determines the least cost expansion plan given a set of alternative technologies. Prior efforts have focused on determining the value of distributed resources by deferring an existing expansion plan (Hoff (1996), Orans (1991)). This approach has been critically challenged (Feinstein (1998a), Lesser (1999)). The new approach discussed in this guidebook is designed to find least cost expansion plans directly. Such plans will include distributed resources if and only if such technologies are appropriate to include in least cost expansion plans.

Determining the role of DR in distribution systems is both an engineering problem and an economic problem. EPRI-supported economic planning research has produced the current state-of-the-art method known as the Area Investment Planning Model. The purpose of this model is to develop least cost expansion strategies for distribution systems. The tool allows development of strategies that explicitly include DR options. The area planning methodology addresses two aspects of the problem: (1) the fact that distribution is a system and thus requires a systems analysis, and (2) the fact that future load and costs are uncertain, necessitating planning under uncertainty and risk management.

Five sections follow. Section 2 summarizes some of the early DR planning methodology. This section is included for completeness and contrast and may be skipped by the application-oriented reader. Section 3 outlines the new strategic approach to DR planning. Section 4 describes the methodology that supports the strategic approach. Section 5 is an analysis tutorial using the Area Investment Strategy Model. Section 6 contains two examples based on utility case studies.

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SUMMARY OF EARLY STUDIES

Introduction

The purpose of this section of the guidebook is to place the Area Investment Strategy Model in context. This section is included for completeness and contrast. It may be skipped or skimmed lightly by readers with an application orientation.

The early planning studies, including the Delta Model applications at Wisconsin Electric (described below), are based on the idea that the benefit of DR investments is due to their ability to defer or replace investments in traditional T&D technologies. The early studies assumed that a company had a plan for capacity expansion and that DR could defer that plan, perhaps indefinitely.

Although interest in DR planning was renewed in 1992 (Feinstein (1993), Pupp (1993)), the idea of measuring the benefits of siting small-scale dispersed storage and generation assets in a utility's transmission and distribution system had been explored in several earlier reports (Chovaniec (1978), Ma (1979), Lee (1979), Bullard (1980), Davitian (1981), Finger (1981), Koenig (1981), Tabors (1981), Ma (1982), Rigney (1982), Sobieski (1985)). Those benefits included reduced capacity requirements of the transmission and distribution system, improved reliability, and lowered losses. The idea that is characteristic of the DR concept is that the distributed elements meet local area transmission, substation, and feeder peaks when and where most useful. Investment planning under the DR concept highlights transmission and distribution costs, and how distributed assets can affect those costs, compared with the kind of planning practices that tend to ignore the impacts on the distribution system and focus mainly on central generation.

Examples of DR planning include an analysis of the costs and benefits of siting photovoltaic generation at a substation (Shugar (1991)), a study of the possibility of deferring a transmission line upgrade using targeted DSM to reduce the peak load (Orans (1991), and studies that measured the benefits of local storage applied to shave peak loads (Zaininger (1990), Chapel (1993)). In each of these studies, the net benefits of DR investments were equal to the difference between the capital cost saved by deferring a planned transmission or distribution system investment and the capital cost incurred by installing the distributed resource. The main idea in that determination of net benefits is that the capacity provided by the DR investment, although far smaller than the capacity provided by the planned transmission or distribution investment, may be used to decrease the peak load when it occurs. Therefore, since investments are planned to meet anticipated peaks, the investments can be delayed if the peak load is reduced. The benefit of delay is the change in present value of the investment. The cost of the delay is the capital cost of the DR technologies used to reduce the peak. The net benefit is the difference of those two values. Virtually all economic analysis of DR alternatives is performed on this basis.

The early planning methods are summarized below.

Deferring T&D investment Plans

Two arguments are often made for deferring large capital investments with small capital investments: time value of money and asset utilization. Because DR investments tend to be smaller and have lower total cost than traditional T&D investments, a benefit is achieved, based on the opportunity cost of deferred capital expense, when the small investment is used to defer the large investment. Money is saved when expenditures are delayed, all other things equal. Thus, if the objective is to minimize costs, deferral has legitimate cost saving benefits.

In contrast, while it may be appealing to maximize asset utilization as an investment goal, using such an objective is not necessarily cost reducing. The present value of the cost of an investment policy depends on a number of variables including the size and relative costs (capital and operating) of the alternative technologies. In fact, it is easy to show that using the small investment to increase utilization can, in many cases, result in higher present value of the total costs.

In practice, the deferral methodology has not been used to find investment solutions with minimum total costs. In most cases, the solution found tends to maximize deferral as long as deferral is cost effective. This has an interesting effect: maximum deferral results in delaying T&D investments until the cost of deferral equals the benefit. This means that the two solutions, the original policy and the policy deferred by DR investments, will tend to have equal cost (Lesser (1999)).

PG&E's Area and Time Specific Costing

There was some interest in distributed generation in the late 1970s but the idea of using DR was not seriously considered by the electric power industry until the late 1980s. At that time the topic emerged at Pacific Gas and Electric Company. The triggering event was rapid urban growth and the resulting costly investments in distribution infrastructure. This caused some increase in costs for all utility customers and customer complaints, especially from customers in the non-growth areas.

Based on these events, PG&E undertook a large effort to document the differences in actual cost of service among their distribution planning areas. The PG&E rate department developed an area and time specific costing methodology to support the costing study. The objective of the methodology was to allocate investment cost to the customers and peak hours that are responsible for the capacity needs. The area and time specific costing methods were used to demonstrate the investment costs necessary for meeting new incremental load, and to show that when the expansion costs were allocated to a few hours of peak or nearly peak load, the cost of serving that load could be quite high.

PG&E applied the area costing methodology to their Delta planning area and used the results to justify DSM programs in the growing area. This was the first case of targeting DSM to avoid capital investments; prior justifications of DSM were based on energy savings. The study is summarized in the EPRI report TR-100487s, "Targeting DSM for Transmission and Distribution Benefits" (Orans (1991)). The PG&E area and time specific methodology demonstrated that area T&D infrastructure costs can be very high, especially from the perspective of the need to serve a peaking load for just a few hours per year. This suggested that perhaps the industry should explore non-traditional alternatives for meeting peak loads.

From a methodological perspective, PG&E's area and time specific costing is flawed. The approach allocates capital costs to peak load hours and across years. These allocations are necessarily arbitrary. They are based on accrual accounting methods and do not reflect actual cash flows.

The interesting implication of the PG&E costing methodology is not that T&D deferral is a good idea (although the method has been used to promote investment deferral). Instead, the key contribution is the insight that the best plan for meeting load increases is at least partially driven by local conditions. These conditions includes local load growth and shape, the cost of adding the necessary local T&D infrastructure, and the needs and willingness-to-pay of local customers.

The Delta Model / Methodology

This model builds upon the PG&E area and time specific costing methodology and is a capacity expansion tool (Orans (1991), Horii (1996)). The Delta methodology addresses four questions:

1. What are the magnitude and timing of peak loads in a distribution area?

2. How will local resources (DSM and local generation) affect peak load at both bulk and local levels?

3. What are the area- and time-specific costs (transmission and distribution avoided costs)?

4. How will DR affect the planning area's expansion plan?

The objective of the Delta methodology is to find the least cost mix of DR and local T&D over some planning period, say 20 years. For each year of the plan, the model produces the least cost amount of DR and investment in T&D capacity. The model makes two key assumptions: (1) load is predictable and thus the capacity plan is based on a foreseeable load path, and (2) a given local T&D plan exists and the optimal strategy is found by deferring this plan using DR.

Wisconsin Electric Study

Initially the Delta methodology was used by Wisconsin Electric to explore whether local generators and DSM could be used to defer T&D planned investments. In retrospect, this study produced two important methodology-related observations made by distribution engineers and planners at WE. After observing the Delta model result, the WE planners argued that when they developed their T&D plan, they had not considered DR, and if they had they would have come up with a different plan. That is, consideration of DR would have changed the T&D plan and not just deferred the plan. The WE engineers also argued that load uncertainty was an important planning consideration and that the Delta model and other existing approaches assume that future load, among other variables such as siting uncertainty and technology costs, is known with certainty. WE staff encouraged EPRI to proceed with the development of a methodology that would jointly determine the least-cost mix of T&D and DR options, and that would explicitly incorporate load growth and other important uncertainties.

What Has Changed since Initial DR Studies

The initial discussions of DR were focused on the deferral benefits of single installations. DR is now being considered and promoted as an investment strategy. This creates a need for a new "strategy focused methodology." The purpose of the methodology should be to determine whether DR makes sense as a broad strategy, rather than which specific DR technologies should be dispatched during any particular hour or year. Current EPRI-supported modeling efforts are directed toward the strategic analysis. This refined purpose requires a change in focus with respect to the structure of models and the data required to use them.

The EPRI Area Investment Strategy Model is the result of: (1) applications of the PG&E time- and area-specific costing, (2) applications of the Delta model at several companies including WE, and (3) encouragement from WE engineers and others to develop a better planning tool.

3
STRATEGIC DR PLANNING

The purpose of this section is to describe the main ideas encountered in strategic planning for the distribution system, with particular attention to the role of distributed resources. The discussion is general and somewhat theoretical. Application oriented readers may wish to skim this section and pass on to the more applied portions of the guidebook.

Distribution assets comprise over 40 percent of total electric utility investment. Although it would appear natural for distribution planning to focus on long-term investment issues, in the past a distribution planner's main objective has been maximizing system reliability within a fixed budget. Distribution planning has traditionally focused on meeting near-term customer demand by adding transformers and feeders. Little attention was given to alternative technical solutions, the appropriate scale for investments, or the long-term implications of resource commitments.

Maximizing reliability within a fixed budget was achieved through application of planning criteria that minimized the effects of delivery problems and unexpected increases in demand (supply and demand disruptions). During normal conditions, outages have not been acceptable. During disruptions (due to equipment failures or rare high demand levels), application of the planning criteria have limited the outages to a few hours per year.

Recent methods have taken a longer-term perspective. The longer-term perspective requires the planner to specify the future load growth and capacity expansion plans in order to determine the impact of deferring the plan using smaller, modular technologies (distributed generation and load control programs). While this approach does address one important piece of the problem – the long-term implications of large investments – it neglects another, equally important, piece, which is the uncertainty that accompanies any attempt to project more than a year or two into the future. Hence, recent methods that adopt a deterministic, but long-term, perspective are insufficient.

Reformulation of Distribution and DR Investment Planning

The new approach to investment planning, described in this subsection, reformulates the objective and the analysis methods, and focuses on the distribution system.

Focus on the Distribution System

In the initial excitement over the DR concept (then referred to as the "distributed utility" (Feinstein (1993), Pupp (1993)), it was believed that DR investments could possibly be substituted for investments in central generation, bulk transmission, and local (sub-) transmission and distribution (Logan (1995), Lenssen (1996)). It now appears that the main effect of DR investments will be at the distribution level. Therefore, EPRI is developing methods and creating software designed to support distribution planning. It is certainly appropriate to consider cost savings in central generation and bulk transmission that may result from DR investments in the distribution system.

Structure the Problem Recognizing The System Nature Of Distribution Planning

Because electric distribution systems are composed of interconnected components, identifying alternatives for increasing capacity and expanding the systems over time requires identifying specific load-growth locations and the bottlenecks in the system that limit capacity. However, EPRI experience suggests that problem structuring is fundamentally an issue of doing careful thinking about the problem and far less a matter of doing engineering analysis and running load flow models.

Remove Deferral Bias

The EPRI approach to DR planning is designed to remove the deferral bias that is present in the current view of distributed resources. Instead of selecting DR investments to defer planned capacity installations, the new approach selects DR investments to minimize the total cost of service.

Minimize the Cost of Service

The objective of DR investments is the same as that of any other investment in infrastructure: minimize the cost of service subject to meeting appropriate reliability and obligation to serve constraints. Meeting this objective may entail the delay of more traditional infrastructure investments, but such delay is not the end objective of DR investments.

Select DR Investments to Hedge Against Future Uncertainties

Distributed resources are not a substitute for infrastructure investments. The real value of DR investment is that it permits the planner to wait, or fill a gap, without making a risky, large, long-lived capital commitment.

This objective is not inconsistent with minimizing the cost of service. In fact, in the context of finding the optimal investment policy, the hedging possibilities are only selected when they provide least-cost solutions.

The physical nature of the DR investments is what permits them to be used as hedges and what prevents them from being used as substitutes for infrastructure. DR investments are modular, since they come in relatively small capacity increments. They are flexible, since they can be relatively easily sited and, in many cases, moved from one location to another in the distribution system. Thus DR investments can be readily positioned to anticipate needs while future conditions are uncertain, and can also respond to changing needs as uncertainties are resolved.

Base Calculations on Actual Cash Flows

A change in economic analysis from most earlier methods is that the actual cash flows, capital plus operating, are used. One should eliminate the use of arbitrary marginal avoided costs wherever possible.

Explicitly Incorporate Uncertainty Into The Analysis

Load Growth Uncertainty

The primary uncertainty in DR applications in local distribution planning areas is whether anticipated load growth will occur. For distribution planning, a key issue is at what point in the future will load growth result in new capacity requirements. A complete description of potential load trajectories over time is required in order to specify the probability distribution on the time that new capacity is required.

EPRI has developed a dynamic probabilistic model of load growth (Feinstein (1997b)). The basis of the model is a simple yet robust mathematical description of the dynamics of load growth rates using a Markov chain. A straightforward estimation process can be used to specify the parameters of the model. This procedure is integrated into the Area Investment Strategy Model.

Siting Uncertainty

Among the important uncertainties that must be addressed by distribution planners is siting uncertainty. A critical issue is whether sites will be available for infrastructure investments. The relative likelihood of site availability for substations, feeders, and DR investments, such as engines or batteries, is a strategic issue that influences the acceptance of DR as a planning approach. Whether or not a site must be secured before it is actually needed becomes a strategic decision, depending on whether it is easy or not to obtain a site. Further, the effects of regulatory and environmental considerations must be addressed since these effects can influence investment strategy.

Fuel Price Uncertainty

The uncertainty in fuel prices—more generally, operating costs of various technologies—is an effect that must be considered by planners. Operating DR technologies in uncertain conditions makes them somewhat risky. To the extent that different fuels are used by alternate technologies, the differential amounts of uncertainty in future prices can have an effect on choice of investments.

Technology Uncertainty

The uncertainty in technology, either in what is available or what it may cost in the future, is an important aspect of the strategic assessment of DR. For example, although the current capital costs of both photovoltaics and fuel cells are sufficiently large so that neither of these technologies can be generally adopted, the future situation may be different. The consequence of using current DR technologies to delay while waiting for some cost reductions to occur in these other technologies can be discovered.

Integrate DR Into Existing Expansion Plans

If there is an existing plan for a local area, it will be of some interest to see whether integrating DR alternatives can yield a modified plan that is superior. A typical approach to determine how best to integrate DR considerations would be to consider whether delaying the investments in the plan would reduce costs. Some delicacy is required in such an instance, however. It is important to recognize that deferring assets may be beneficial but need not be optimal. Although improvements to existing plans may be achieved, there is no theory that indicates that such improved plans are the best that can be found.

Since many distribution areas do not have a plan, and since distribution investing appears to be reactive, it is more likely that the DR investments would be part of an evolving expansion plan. The EPRI approach to this problem suggests two innovations. First, the distribution system should be recognized as a subsystem that requires its own planning function. Second, planners and other utility (or distribution company) managers ought to recognize that a plan is a policy that describes not just what to do next year but also what to do as the need for capacity evolves over time.

Identify Dynamically Optimal Investment Strategy

The investment strategy that best utilizes DR investments is a dynamically optimal strategy that minimizes the expected net present value of the costs of acquiring and operating the investments over their useful lifetimes. The dynamically optimal strategy is a plan of what to do currently and what to do as uncertainties resolve over time. While the main focus may be on finding an immediate solution to a capacity problem, the least-cost near-term decision cannot be found without taking into account future possible conditions and decisions. Special modeling approaches and algorithms must be applied in order to determine such a strategy. These approaches have been built into the Area Investment Strategy Model.

The Analytical Problem

This subsection describes the economic valuation principles and the analytical questions that must be addressed when solving the investment strategy problem. The analytical issues are: (1) scale economies of the investment alternatives, (2) limited scope for modular investments (distributed resources and load control programs), (3) uncertain future load and costs, and (4) the need to include load control programs as part of the portfolio of investment alternatives.

Investment Valuation Principles

Investment capacity planning is guided by a set of economic valuation principles. Four key principles are stated below. These underlie value estimation for the EPRI DR and distribution planning methodology.

1. Deferral of capital projects has direct economic value. This is the result of the opportunity cost of financial capital; that cost is measured by the discount rate when doing net present value calculations. The higher the cost of financial capital the greater the value of deferral. Large investments providing over capacity in the near-term can be good investments if the capacity is likely to be eventually needed.

2. There is a tradeoff between economy of scale and flexibility. Large capacity resources are generally cheaper per unit capacity but provide limited future decision flexibility. Small investments defer large investments and provide the option to revisit the large decision. This option to delay allows for learning before deciding.

3. The value of being able to revisit a large investment decision depends on the nature of load uncertainty. If there is no uncertainty, there is no potential for learning and no value associated with revisiting the decision. Even with uncertainty, if the uncertainty is not reduced over time, there is no value associated with delaying to revisit the decision.

4. Independent of uncertainty, modularity has value. Small increments of capacity track load more closely and can be easier to site.

Scale Economies - The "Two-Edged Sword"

In most cases, there are scale economies associated with larger capacity investments. Scale economies suggest that it may make sense to invest in a large increase in delivery capacity if that capacity will eventually be needed. Two kinds of errors can result from an incorrect analysis of the benefits of economies of scale. The first error is to avoid a large investment because the first cost is large but, in fact, the large investment is the least cost strategy over time. The second error occurs if a large investment is made because the unit cost is relatively small but that investment, when correctly evaluated, is not the least cost choice.

Limitation of Scope - Modular Investments & DSM

The investment question is under what conditions should traditional upgrades be avoided by exercising modular options to meet uncertain customer needs for reliable and economic service? When addressing this question, the analysis must take into consideration two facts. First, the marginal cost of those investments tends to increase, such that if modular investments are pursued aggressively, the cost of providing a fixed increment of capacity increases. This is illustrated in Figure 3-1.

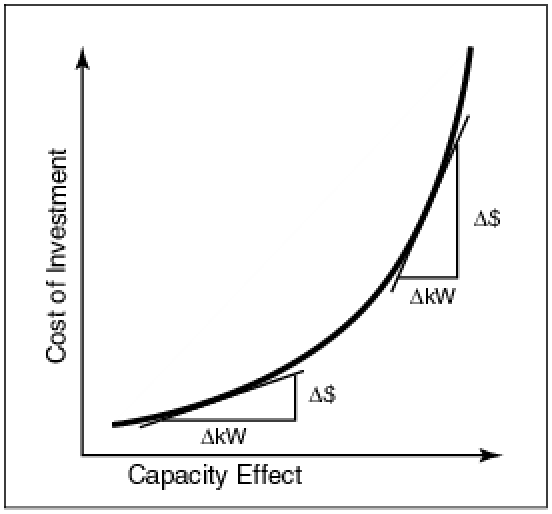

Figure 3-1
Limitation of Scope

Second, in the context of a distribution system, there is a physical limitation on the capacity effect of modular and DSM investments. It may not be possible to locate the distributed assets where they are needed. It is possible that the capacity effect of these investments will be limited. This situation is illustrated in Figure 3-2.

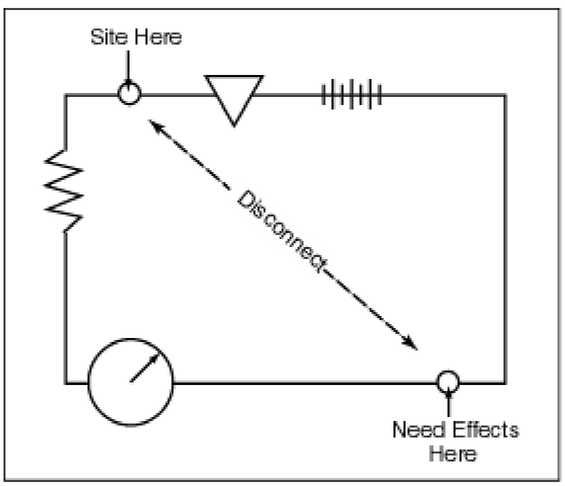

Figure 3-2
Physical Limit on Capacity

Uncertainty in Value of Investments

Load uncertainty makes the scale of distribution investments an important strategy issue. Smaller scale units provide a hedge against the risk that loads do not materialize. Further, because learning may occur over time, small-scale investments provide the opportunity to delay and revisit large-scale investment decisions. However if load does eventually materialize or if the cost of the infrastructure increases as areas develop, there may be significant cost penalties associated with deferring distribution upgrades using small-scale distributed technologies. Figure 3-3 suggests that the preferred choice between a large or small capacity investment depends on the forecast of load growth.

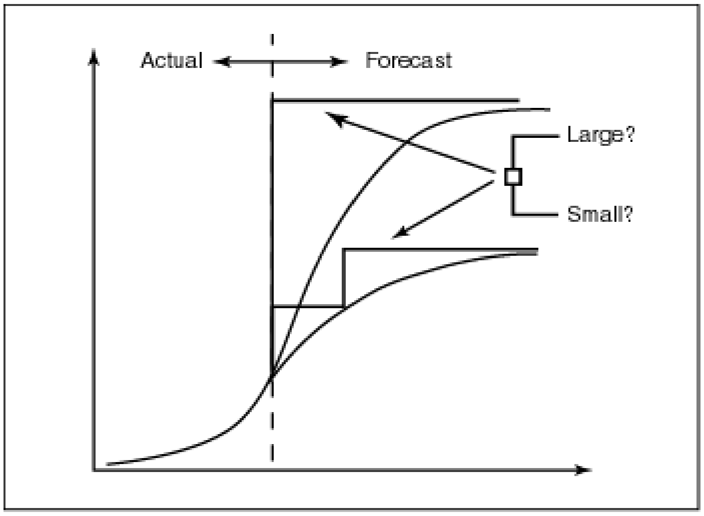

Figure 3-3
The Dilemma of Uncertainty

Load Management Programs

Another source of complexity is the existence of load management programs. System engineering combined with market intelligence can (1) establish some appropriate level of unplanned outages (unserved energy), and (2) identify investment alternatives that provide the commensurate level of service. It may also make sense to have selective outages for some customers (planned unserved energy). In some situations, such load management programs may be one of the more cost-effective alternatives for providing peak capacity relief. If this is true, these programs should be treated as an infrastructure investment alternative. Load management programs also give the planner the opportunity to fine-tune the level of service provided to individual customers as part of a complete investment strategy.

4 NEW METHODOLOGY FOR STRATEGIC DR PLANNING

Introduction

EPRI, in conjunction with a number of utilities, has developed a new analytical approach for DR and distribution infrastructure investment planning. The Area Investment Strategy Model is an integral part of this new approach. In this subsection we summarize the new approach and the associated analytical tools.

The new strategy development process builds on current reliability-focused planning. The approach is a two-step process. First, system engineering is used to establish the capacity of the existing local area distribution network and to identify alternative investment sequences that provide enough capacity to maintain a given service level. The Area Investment Strategy Model is then used to identify optimal sequences of investments that are conditional on future load conditions and other uncertainties. The sequences describe which investment to make today and how to respond as load and other uncertainties are resolved. The sequences are optimal since they provide the pre-defined level of service at least cost.

The Area Investment Strategy Model captures the uncertainty of future load and costs in the design of plans for infrastructure additions. It provides the cost and risk information that utilities need to build business cases for least-cost investment strategies.

Purpose of the Area Investment Strategy Model

The purpose of the Area Investment Strategy Model is to enable the user to determine local distribution area expansion plans that are least-cost under uncertainty.

An expansion plan is a timed sequence of investment decisions that is contingent upon the future occurrence of various states of nature. For example, if load in an area were to begin to grow rapidly, the optimal expansion plan would recognize the need for capacity expansion in the area sooner than it would be needed if load were growing less rapidly. The expansion plan itself is described in a contingent manner: e.g., install capacity amount A of type X at time t_1 if load growth is rapid, install capacity amount B of type Y at time t_2 if load growth is moderate, and install capacity amount C of type Z at time t_3 if load growth is slow.

The expansion plan that is least-cost under uncertainty is the plan whose expected net present value is smallest compared to all feasible expansion plans considered in the analysis. Uncertainty means that the planning context is one in which the user's lack of surety about future conditions of load growth, fuel costs, regulatory environment, technological progress, site availability, and possibly other important variables, is a major influence on the investment decisions actually made.

The appropriate investments when future load on the distribution system is certain are very different than those when future load is uncertain. It is that difference that motivated the construction of the strategy model. When future conditions are uncertain, then future cash flows are uncertain, and the optimal policy minimizes the expected present value over all future cash flows, where by expected we mean the probability-weighted average of the uncertain cash flows.

Unlike other models that rely on very complex and detailed data inputs, the strategy model requires relatively little in terms of data. This is because the design of the strategy model replaces the need for data with a sophisticated model structure that can extract, from the data, sufficient information to determine optimal investment strategies. The fundamental model design tradeoff is between a primitive model structure driven by exhaustive data sets compared to a mathematically robust model, with internal optimization logic, that requires an easily assembled data set.

Overview of the Operation of the Model

The Area Investment Strategy Model formulates and solves a dynamic optimization problem. The problem is represented as a decision tree. The tree contains a sequence of nodes; each node is either a decision node or a chance node. At a decision node, a choice of paths can be made. At a chance node, the path that actually occurs is not chosen but rather is governed by a probability distribution. All the uncertain variables in the problem are modeled using probability distributions on chance nodes. A policy is a complete path through the tree, such that the choice made at each decision node is specified conditionally with respect to the sequence of resolutions of the prior chance and decision nodes, and the combination of choices and uncertainties determines the cost along each path. The optimal policy is the one that minimizes the expected cost through the tree.

An example of a decision tree is provided in Figure 4-1 below. Beginning at the left, the first decision is to choose between A and B. These could be two alternative capacity investments for a planning area. If A is selected there follows a chance node. The chance node could describe the uncertainty in future load growth. With probability p, no further decisions need be made, which is symbolized by the triangle at the end of the branch emanating from the chance node. With probability 1-p, the next decision is to choose between C and D. Regardless of which one is selected, no further decisions are required. If B is selected initially, there follows a chance node such that with probability q, the next decision is to choose between E and F. Regardless of which one is selected, no further decisions are required. Alternatively, after B is selected, with probability 1-q, the next decision is to choose among E, F, and G. Notice that the alternatives can change depending upon the condition achieved.

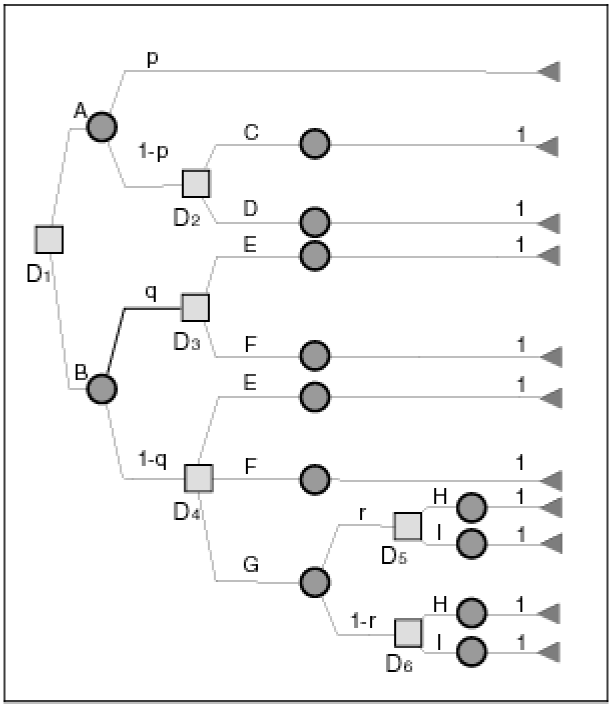

Figure 4-1
A Simple Decision Tree Structure

Choosing E or F means that no further decisions are required. Choosing G leads to another chance node, such that with probability r, the next decision is between H and I. Similarly, with probability 1-r, the next decision is between H and I. No further decisions are required.

A policy is a complete setting of the decision nodes for every possible resolution of the chance nodes. Thus, a policy is a set of contingent actions that specifies what to do in any state of the world. For example, one policy is: select A at the first decision node and if the lower branch of the chance node occurs, select C. Here is an alternate policy: select B, followed by E if the upper event occurs and G if the lower event occurs; after G, choose H in either case. The optimal policy is the path that is least cost. The algorithm that determines the optimal policy has only two rules: (1) replace all chance nodes by their expected cost, and (2) replace all decision nodes by the alternative with minimum cost over all possible alternatives.

The Area Investment Strategy Model begins by setting up the tree structure, using the constraints specified by the user to eliminate infeasible paths. The salvage value specifications provided by the user permit the model to compute the cost at the end of the tree. Once costs at the end of the tree have been determined, it is straightforward to compute the expected value of each alternative at each decision node. That expected value is based on the probabilities of uncertain events, such as load growth, as specified by the user. After computing all such expected values, the model searches the tree to find the path that is least cost. Results of the Area Investment Strategy Model analysis are presented in a format that is consistent with the tree structure used to solve the problem. Illustrative examples of the tree structure and the operation of the model are given in the next section.

5
AN INVESTMENT ANALYSIS TUTORIAL

This section discusses the modeling process and provides an example of how the Area Investment Strategy Model can be used to determine the best investment policy for a local area and to provide insights into the key issues affecting strategic policy. A sequence of tasks is described, designed to implement the Area Investment Strategy Model within an organization and to develop the capability to support local area decision making.

To illustrate the process of getting started with the Strategy Model, the investment planning problem of a fictitious utility, National Power Company (NAPCO) will be analyzed. After describing how to set up the model, an initial base case will be developed from historical data. This initial case will be unrealistically simple; its purpose is to familiarize the new user with the structure of the problem and the handling of input data sets. The results of the first case will most likely be too simplified to use for policy recommendations. An iteration through the analysis cycle will make the model's representation of the electrical system more realistic and complex. A new input set will be developed to represent more accurately the utility's electrical problem and demonstrate many of the features of the Strategy Model. The tasks outlined in this section are designed to increase the user's knowledge of how the model works and how to determine what aspects of a specific problem are important.

To obtain the software, you must be a member of the Distribution Resources Target or the Distribution Business Area. A copy of the Strategy Model along with test data sets is available through:

EPSC/Electric Power Software Center
Suite 120
11025 North Torrey Pines Road
La Jolla, CA 92037
1-800-763-EPSC
(1-800-763-3772)

If you have any problems, you may call Steve Chapel, EPRI, (650) 855-2608.

Analysis Cycle

Before assembling input data and starting to run the Area Investment Strategy Model, it is important to examine what the result of the modeling process will be. The process by which the model is used is as important as the model itself. The model is not a "black box" that will provide a single answer for the least cost investment policy. While the Area Investment Strategy Model will identify the least-cost policy for a specified set of input parameters, support of investment planning decisions involves a great deal more than a single run of the model. Proper analysis is accomplished by many model runs, cycling through the process depicted in Figure 5-1.

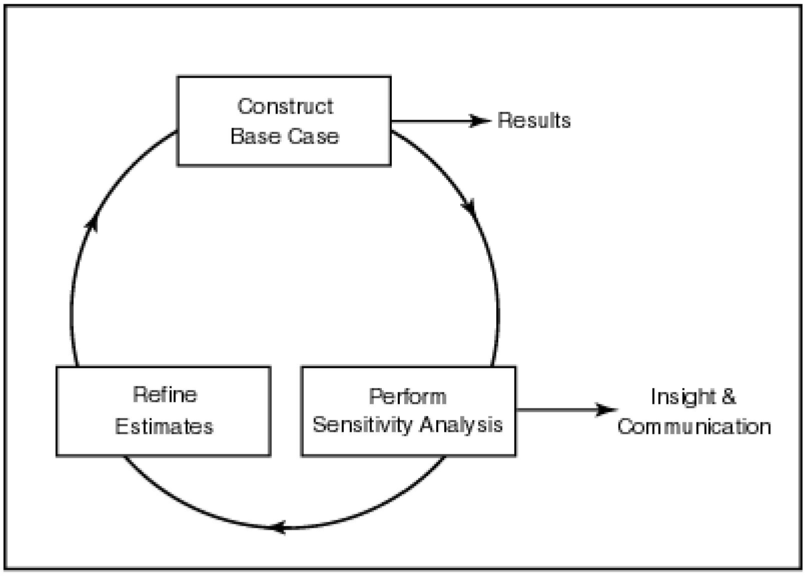

Figure 5-1
Analysis Cycle

The analysis cycle constantly refines one's description of the electrical system, testing the sensitivity of results to changes in inputs and identifying the key issues that affect the structure of the optimal strategy. Examination of the effects on model results when input data are varied provides a quantitative understanding of the critical factors that determine capacity requirements. The refined input description will not only determine the best investment policy, but also indicate how costs vary with policy and illustrate the consequences (e.g., capital and operating costs, investment risks and future load probabilities) of following a particular policy.

Using the Strategy Model

The Strategy Model requires a personal computer and a planner with experience in distribution planning. The planner installs the model on the host computer. The planner gathers the model data, operates the model, interprets the model results, and communicates results and insights to policy and decision-makers. Version 1.5 is relatively fast, taking seconds or minutes for a typical case on current PCs.

Work with Test Cases

The Strategy Model is shipped with three input data sets discussed in this section, along with the resulting output sets. The input files are case1.aip, case2.aip, and case3.aip. The output files are case1.report, etc. These test data sets serve three purposes.

The test data:

1. demonstrate that the model has been correctly installed on the computer,
2. provide data sets for the tasks described in this section, and
3. provide templates for future data sets.

Structure the Problem

It is helpful to analyze investment planning problems in general before studying the specifics of one's own situation. This provides a context for the problem and identifies the issues appropriate for further investigation. It also highlights the items that will be candidates for sensitivity analysis following initial model runs.

There are five fundamental types of issues that must be evaluated in order to determine the least-cost expansion strategy for a local area. The first three issues are economic issues that exist under both certainty and uncertainty. The last two issues exist because the future is uncertain.

- Value of Lower Life-Cycle Costs
- Value of Deferral
- Value of Tracking Load
- Value of Flexibility
- Value of Learning

Value of Lower Life-Cycle Costs

Under certainty, the issue of which technology to use to satisfy load is a simple engineering-economic problem. The objective is to minimize the present value of the cost stream over time among the various alternatives. If two investments have the same size, the solution is determined by evaluating the tradeoff among capital costs, operating costs, and investment life. It is easy to demonstrate that the best alternative will be the one that has the lowest annualized, or levelized, cost.

Value of Deferral

Deferral of an investment has a direct economic value, which is the opportunity cost of money. To see this, consider the example in Figure 5-2, which shows two alternatives for meeting load over some time period t. One alternative is to install the larger investment (capacity C, capital cost $X) at time 0, which would serve load until time t. The other alternative is to install the smaller investment (capacity C/2) at time 0 and then again at time t/2. Suppose the operating costs are zero and that the capital cost of the smaller investment is half the capital cost of the larger investment. In other words, there are no economies of scale. Also, for simplicity, suppose that t = 2 years. The present value capital cost of the large alternative is $X. The present value capital cost of the smaller alternative is $X/2 plus $X/2(1+r), where r is the discount rate. The discount rate is the cost of capital; for example, if the cost of capital is 10%, this means one must pay $1.10 in order to finance $1 of investment for a year. If $X = $1,000 and r = 0.1, the present value capital cost of the large investment is $1,000, whereas the present value capital cost of the small investment is $955. The small investment has an advantage of $45 simply because it defers the capital expenditures.

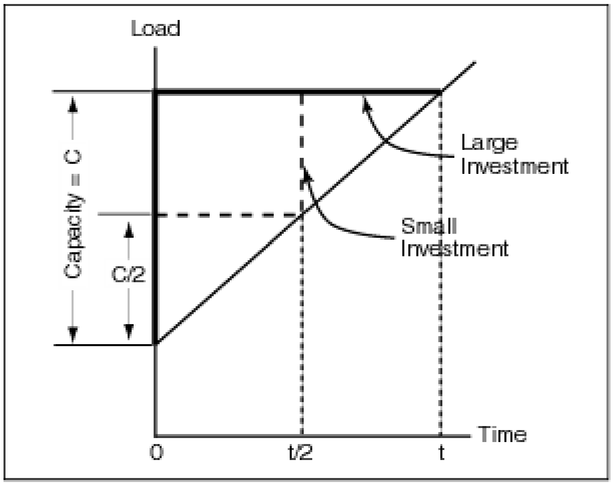

Figure 5-2
Benefits of Deferral

The cost of money, or the time value of money as it is sometimes called, is more than just an abstract economic concept. Note that if the cost of capital (real discount rate) were zero, there would be no capital cost savings due to deferral.

Value of Tracking Load

Continuing the example of Figure 5-2, it is clear that the smaller investment tracks load more closely than the larger investment (i.e., the average amount of excess capacity is smaller with the modular investment). This can generate several additional types of economic value. For example, suppose that a disruption occurs somewhere else on the system. If a larger unit is installed the average amount of unserved energy will be less, since there is more excess capacity. On the other hand, if the investments themselves are unreliable, failure of the large investment would have twice the negative capacity impact as failure of one of the smaller investments. Perhaps the most direct benefit of tracking load comes with must-run generation units. Note in Figure 5-2 that any operating cost associated with the excess capacity of the larger unit is twice the operating cost of the excess capacity of the smaller unit (compare the areas above the load curve).

Perhaps more subtle, but at least as important for investment planning, are two principles related to the value of modular investments under uncertainty.

Value of Flexibility

Large investments are generally cheaper on a per kW basis, but they provide less flexibility than small investments. Small investments can defer large investments and thereby provide a potentially valuable option to revisit the question of whether to make a large investment. For example, if load growth is uncertain and it is unclear whether a local area will saturate (i.e., achieve a maximum load level) at a high or low level, it may be far less expensive to invest in small investment alternatives and then invest in the larger alternatives if and only if load grows sufficiently high. The test cases below will demonstrate (1) that the value of this type of flexibility can be very high, and (2) that it is impossible to estimate this value without addressing uncertainty explicitly.

Value of Learning

The value of flexibility is intimately related to the value of learning about the investment uncertainties. If an investment uncertainty, such as load growth, is modeled as an independent process, then, by definition, there is no learning. For example, if load in period 2 is independent of load in period 1, then load being high in period 1 tells us nothing about the level of load growth in period 2. However, load growth is a good example of a process in which uncertainties are generally not independent. For example, it may be more likely that load growth will continue to be high after three years of high load growth than it would be for load growth to be high after three years of very low load growth. In this case, we can update our state of information about future load growth by observing past load growth and adjust our future decisions accordingly. For example, it may be appropriate after observing several years of high load growth to invest in a large alternative because the future load growth necessary to justify such an investment is much more likely.

NAPCO Example

National Power Company (NAPCO) wants to analyze the area investment policy for Thapa County. The Thapa County system currently consists of one small and aging substation. The basic decision Thapa County's planners face is whether to replace the old substation with a new one or whether to install a smaller-capacity feeder and then possibly use local generators over time if needed to serve load.

Setting up an Initial Base Case

The first base case constructed will take an intentionally simplified broad-brush approach to the problem. It will ignore uncertainty in load and differences in investment sizes. It will provide a context for setting up the basic model inputs and will provide an initial planning policy under certainty. While simplistic, this type of case allows the new user to get the model working and to begin to understand how the model works. For the experienced user, starting with a simplified case helps to identify areas in which further refinement of the data is necessary, and provides a basis for sensitivity analysis.

For ease of understanding, we shall build up a progression of cases, starting with the simplest possible case and adding complexity as we go. This is the recommended process in a real application. Table 5-1 summarizes the key planning assumptions common to all cases. Table 5-2 shows the model inputs for the simplest possible base case.

Table 5-1
Common Assumptions

COMMON ASSUMPTIONS FOR ALL CASES		
Time Horizon	15 years	
Discount Rate	5%	
Inflation Rate	0%	
Accounting Method	Before Tax Cash Flow	
Initial Load	100,000 kW	
Salvage Value Specifications		
- Price of Capacity at Terminal Time	$10/kW-yr.	
- Escalation of Price of Capacity	1.0	
- Operating Cost of Capacity	$0/kWh	
- Escalation of Operations Cost	1.0	
- Final Load Growth Rate	1%	
O&M Costs	$0	
Emissions Rates & Costs	0	
Load Shape	*Time (hrs)*	*% of Peak*
	0	100%
	8760	0%
Load Growth Trends		
	Growth Rate	
Low	0.5%	
Medium	1.0%	
High	5.0%	

Table 5-2
Base Case Assumptions

BASE CASE			
Technologies	*Size (kW)*	*Cost ($1000)*	
Technology S	25,000	$2,500	
Trend Transition Probabilities			
	Low (0.5%)	*Medium (1%)*	*High (5%)*
Low (0.5%)	*1.00*	0.00	0.00
Medium (1%)	*1.00*	0.00	0.00
High (5%)	*1.00*	0.00	0.00
Initial Load Growth Rate		"Low" 0.5%	
Result (NPV Cost $1000)		$ 2,869	

Case Description

The input file for this case is *case1.aip*.

The base case includes a single technology, call it technology S (think of it as a new substation), with capacity 25,000 kW having a capital cost of $2,500,000 (entered as $2,500 since we will assume cost units in thousands of dollars). We assume load grows at a fixed and certain rate of 0.5% per year starting from a base of 100,000 kW. Note that the user can run deterministic cases by assigning a probability of 1.0 to one load-growth trend (in this case, the initial load growth rate is 0.005 and there is probability 1.0 of staying at the initial rate).

For simplicity in this case and in the following cases, we assume the substation has no operating costs of any type, and no losses and unserved energy. We wish to plan over a time horizon of 15 years using a 5% real discount rate (no inflation). Finally, we will use the Cost-to-Go method for salvage value (see the Area Investment Strategy Model User Manual for a complete description of this method) and assume that the price of capacity at the end of the time horizon is $10/kW-yr., the future final growth rate is 1%, and that there is no real escalation on capacity price or operating cost after the end of the time horizon.

Case Results

The optimal policy based on this case is shown in Table 5-3. This is a simple example of the Optimal Tree output report. (The Area Investment Strategy Model User Manual has a complete description of the output reports available.) For this simple case, the results are not surprising. There is only one technology, the substation S, and it is large enough to serve the certain projected load (at a certain load growth of 0.5%, the load grows by 7,768 kW over 15 years).

Since S is the only alternative, the optimal policy is simply to install S at the beginning of the time horizon. The value of the optimal policy, which is the discounted present value of the cash flow of costs, is $2,869, which is equal to the capital cost of S plus the discounted salvage value.

Table 5-3
Optimal Strategy for the Single-Technology Case

Decision (Stage 1)	Chance	Decision (Stage 2)
Optimal Value = 2868.60 S at t=0.00, L=100000	p=1.000, t=44.74, g=1.0050	Terminate at t=15, L=107768

Insights and Observations

Although the base case is very simple, we can begin to build insight by performing some simple sensitivity analyses, changing assumptions and seeing how the case changes. The reader is encouraged to run some cases with different inputs. For example, try running the same case for non-zero settings of the salvage value to see how the total cost changes. Also, try both the alternative salvage value definitions.

Another useful exercise would be to add realism by introducing the different components of operating costs to see how they affect the optimal value. Finally, add some losses and unserved energy costs to get a feeling for their impacts on the bottom line.

Introducing a Modular Technology

Case Description

We next investigate two subcases that introduce an additional modular technology, a feeder F that has 1,250 kW capacity, or half that of S. The user should modify case1.aip to create the inputs for this case. The first subcase is summarized at the top of Table 5-4 (Introducing a Modular Technology [no economy of scale]). This subcase is identical to the base case except that there is an additional capacity alternative, Technology F, that is exactly half the size of Technology S and has exactly half the capital cost ($1,250). Thus, both alternatives have the same unit cost of $100/kW. The second subcase, summarized at the bottom of Table 5-4 (Introducing a Modular Technology [with economy of scale]), introduces a perhaps more realistic Technology F, which is half the size of Technology S but with twice as high a unit cost of $200/kW.

Table 5-4
Introducing a Modular Technology

INTRODUCING A MODULAR TECHNOLOGY (NO ECONOMY OF SCALE)			
Technologies		*Size (kW)*	*Cost ($1000)*
Technology S		25,000	2,500
Technology F		12,500	1,250
Trend Transition Probabilities			
	Low (0.5%)	*Medium (1%)*	*High (5%)*
Low (0.5%)	1.00	0.00	0.00
Medium (1%)	1.00	0.00	0.00
High (5%)	1.00	0.00	0.00
Initial Load Growth Rate		"Low" 0.5%	
Result (NPV Cost $1000)		$2,039	

INTRODUCING A MODULAR TECHNOLOGY (WITH ECONOMY OF SCALE)			
Technologies		*Size (kW)*	*Cost ($1000)*
Technology S		25,000	2,500
Technology F		12,500	2,500
Trend Transition Probabilities			
	Low (0.5%)	*Medium (1%)*	*High (5%)*
Low (0.5%)	1.00	0.00	0.00
Medium (1%)	1.00	0.00	0.00
High (5%)	1.00	0.00	0.00
Initial Load Growth Rate		"Low" 0.5%	
Result (NPV Cost $1000)		$2,869	

Case Results

The results are quite interesting. Table 5-5 shows that the optimal policy for the No-Economy-of-Scale case is to use the smaller Technology F. Note that the NPV cost of $2,039 is lower than the $2,869 cost associated with Technology S, even though both S and F have the same cost per kW. This cost reduction occurs because of the smaller technology's ability to follow load more closely and defer a portion of the investment (see the Value of Tracking Load section above).

Table 5-5
Optimal Strategy for the No-Economy-of-Scale Case

Decision (Stage 1)	Chance	Decision (Stage 2)
Optimal Value = 2039.44		
F at t=0.00, L=100000	p=1.000, t=23.62, g=1.005	Terminate at 15, L=107768

Now consider the optimal policy for the Economy-of-Scale case shown in Table 5-6. We see that the least-cost policy is the same as in the base case: install the large Technology S immediately to serve load over the time horizon. Thus, we see that the economy-of-scale benefit of Technology S is worth more than the load-matching benefit of Technology F.

It is interesting to note, with the low load growth of 0.5%, we had to increase the cost of technology F to $180/KW before the economy-of-scale benefit outweighed the load-matching benefit.

Table 5-6
Optimal Policy for the Economy-of-Scale Case

Decision (Stage 1)	Chance	Decision (Stage 2)
Optimal Value = 2868.60		
S at t=0.00, L=100000	p=1.000, t=44.74, g=1.0050	Terminate at 15, L=107768

Insights and Observations

The model explicitly trades-off economies of size as captured by load matching ability versus economies of scale as captured by capital costs. Try running some cases with different capital costs and different technology sizes. You will find that there is no general rule for anticipating which effect will dominate strategy in any particular situation. Indeed, a key benefit of this type of model is its ability to make economic tradeoffs of these and much more complex situations.

But we are not done with our evaluation of the modular technology. In fact, we have left out a key element of the value of a small modular technology; that is, its ability to provide management flexibility. We shall investigate this feature in the next case.

Uncertainty and Management Flexibility

Case Description

We now examine the implications of adding load growth uncertainty into the case. The input file for this case is case2.aip. We shall see that uncertainty has profound implications for choosing the best strategy as well as for accurately valuing the benefits of a modular technology. Table 5-7 shows inputs for a new case, titled Uncertainty and Management Flexibility. The new case is identical to the previous case except: 1) the load transition matrix now has probabilities other than one or zero, and 2) we assume that technology F costs $1.95 million ($156/kW). This means that load is now modeled probabilistically – the model reflects explicitly the fact that load is uncertain. The “steady state probability” is the long run average fraction of time that load will be in any of the three growth states. The steady state probability and the reason for including results with S and F only are explained below.

Table 5-7
Management Flexibility Case

Uncertainty and Management Flexibility			
Technologies		*Size (kW)*	*Cost ($1000)*
Technology S		25,000	2,500
Technology F		12,500	1,950
Trend Transition Probabilities			
	Low (0.5%)	*Medium (1%)*	*High (5%)*
Low (0.5%)	0.80	0.20	0.00
Medium (1%)	0.80	0.10	0.10
High (5%)	0.10	0.10	0.80
Steady State Prob.	0.74	0.17	0.09
Initial Load Growth Rate		“Low” 0.5%	
Result (NPV Cost $1000)		$3,547	
-- with S only		$3,727	
-- with F only		$3,677	

The table of load growth probabilities is called the transition matrix. The transition matrix contains the probability of various load growth rate levels in the next period, given the current load growth trend. For example, if the load is currently growing at 0.5% (Low), then the probability that next period’s trend will be Low is 0.8; the probability that next period’s trend will be Medium (1.0%) is 0.2; and there is no chance of jumping from the lowest trend to the highest trend in a single period. However, if the current trend is Medium, there is a 0.8 chance of jumping to Low, and a 0.1 chance of either jumping to High or remaining in Medium. Finally, if the current trend is High, there is a 0.1 chance of jumping to Low or Medium and a 0.8 chance of staying at High.

The user specifies the levels associated with each trend, the trend name and the probabilities characterizing the uncertain evolution of the load as model inputs. The second case in section 6, below, illustrates the use of the Load Assessor Tool to determine the transition probabilities.

Case Results

Table 5-8 shows the optimal tree. This is a somewhat more complex example of the output report provided by the model. The tree indicates now that the optimal strategy is what we call a contingent policy. Start with the smaller Technology F. If load growth is fast enough so that new capacity is needed before the end of the 15 year period, then install Technology S. If load growth has been very low (probability 0.619 of average growth of 0.57%), F will cover any load growth to the end of the planning horizon. But, in the fast-growth contingency, if load continues to grow at a high rate after S is installed, additional new capacity may be needed in about five and one-third more years, or when nearly 11 years have elapsed since the beginning of the planning period. If so, S should be installed again. The second substation will satisfy load growth in all but the high growth case. If subsequent load growth is high, then right before the end of the time horizon, install Technology S for a third time.

Table 5-8
Optimal Strategy with Management Flexibility

Decision (Stage 1)	Chance	Decision (Stage 2)	Chance	Decision (Stage 3)	Chance	Decision (Stage 4)	Chance	Decision (Stage 5)
Optimal Value = 3546.89								
F at t=0.00, L=100000	p=0.619, t=20.78, g=1.0057	Terminate: L=108875						
	p=0.271, t=14.68, g=1.0081	S at t=14.68, L=112500	p=0.546, t=34.64, g=1.0058	Terminate, L=112707				
			p=0.306, t=22.01, g=1.0092	Terminate, L=112825				
			p=0.148, t=7.18, g=1.0283	Terminate, L=113500				
	p=0.111, t=5.40, g=1.0220	S at t=5.40, L=112500	p=0.427, t=34.46, g=1.0058	Terminate, L=118967				
			p=0.309, t=20.72, g=1.0097	Terminate, L=123458				
			p=0.264, t=5.30, g=1.0386	S at t=10.70, L=137500	p=0.279, t=28.61, g=1.0059	Terminate: L=140996		
					p=0.279, t=16.70, g=1.0101	Terminate: L=143545		
					p=0.442, t=4.02, g=1.0424	S at t=14.72, L=162500	p=0.243, t=24.60, g=1.0058	Terminate, L=162762
							p=0.255, t=14.14, g=1.0102	Terminate, L=162956
							p=0.502, t=3.21, g=1.0456	Terminate, L=164519

Thus, in this case, under the optimal (least-cost) strategy there four possible sequences of installations that optimally serve load for 15 years: F or F-S or F-S-S or F-S-S-S. Moreover, the actual installation sequence will depend on the resolution of the load uncertainty over time.

Insights and Observations

Part of the value of a modular technology is the ability it affords to “wait and see” before making a big commitment. The optimal strategy under uncertainty takes advantage of management’s ability to react. We call this management flexibility. One of the features of the model is that it may be used to attach an economic value to management flexibility.

Note that the overall cost of the optimal strategy is $3,547. This has little meaning until we run some comparative cases. We ran two additional cases with the same load forecast, one assuming only Technology S was available, and one assuming only Technology F was available. (These cases are easy to run using the Installation Constraint feature, which is an option under the model’s main Edit menu. See the Area Investment Strategy Model User Guide for details.) The results are shown at the bottom of Table 5-7.

The classic engineering-economic analysis would conclude that the value (i.e., the net benefit minus cost) of the small technology is equal to the difference between the total cost with the large technology (S-only cost $3,727) and the total cost with the small technology (F-only cost $3,677), or $50. However, this would be a serious underestimate of the value of the small technology as it assumes the utility must live with an inflexible strategy. The proper comparison is between the case in which only the large technology is available and the case in which both technologies are available ($3,547). Thus, the true value of the small modular technology is $180, which is much higher than the inflexible-strategy value.

In this case, over 70% of the total $180 value is derived not from the cost characteristics of Technology F but from its strategic contribution to management flexibility. The combination of alternatives working together in a dynamically optimal strategy creates real economic value that can only be estimated by explicitly modeling the uncertain environment in which the alternatives operate.

As a side note, the model’s ability to analyze dynamically changing strategies can help utility planners by giving guidance as to what to monitor as time goes by.

Learning

Case Description

A key feature of the model is that it explicitly takes into account the ability of the utility to learn about load growth tendencies as load grows over time. A flexible strategy can take advantage of the ability to learn about future load tendencies from observing current load trends. Learning can greatly influence the optimal strategy and its costs. To illustrate how the strategy developed in the case above takes advantage of learning, we developed the comparative No-Learning case summarized in Table 5-9. The input file for this case is *case3.aip*. This case has precisely the same average growth characteristics as in the Uncertainty and Management Flexibility case. This is accomplished by keeping the steady-state probabilities of being in any load state the same. Recall that the steady state probability is the long run average fraction of time that load will be in any of the three growth states.

Table 5-9
No Learning Case

No Learning			
Technologies		*Size (kW)*	*Cost ($1000)*
Technology S		25,000	2,500
Technology F		12,500	1,950
Trend Transition Probabilities			
	Low (0.5%)	*Medium (1%)*	*High (5%)*
Low (0.5%)	0.74	0.17	0.09
Medium (1%)	0.74	0.17	0.09
High (5%)	0.74	0.17	0.09
Steady State Prob.	0.74	0.17	0.09
Initial Load Growth Rate		"Low" 0.5%	
Result (NPV Cost $1000)		$3,680	

Even though the steady-state probabilities are the same in the two cases, there is an important difference. In the first Learning case (Table 5-7) trends tend to persist so that knowledge of the current state tells us something about the future state. For example, if the current state is Low, the probability that the next state is Low is 0.80, whereas if the current state is High, this probability is 0.10. In contrast, in the No Learning case, the probability that the next state is Low is 0.74, no matter what the current state is. (In general, no learning occurs when the rows of a transition matrix are identical)

Case Results

The optimal strategy for the "No Learning" case is very simple: install Technology S and live with it. Thus, we see that even though the two load environments are the same on average, the learning has a profound impact on the strategy. In fact, in the No Learning case, there is no value at all to Technology F! It is never used. Thus, we could say that all the value of Technology F derives entirely from its ability to respond to learning.

Insights and Observations

Another way to interpret these results is that probabilistic dependence has two effects. The first effect, not illustrated here, is that the more likely it is that different growth trends will occur over the planning period, the greater the variance in future load. The second effect is that with probabilistic dependence comes the potential for developing a cost-saving learning strategy.

Pitfalls of Scenario Planning

A common heuristic used to develop strategy under uncertainty is the technique of scenario planning. Scenario planning is simply the study of alternative deterministic plans. Despite its popularity, scenario planning does not get either the policy or the costs right. Scenario planning is supported by deterministic models and thus cannot reflect the dynamic nature of the decision process and help the decision maker decide how to react as the world evolves. We have developed an example to illustrate how unrealistic and misleading deterministic and scenario planning can be.

Scenario planning has several serious pitfalls. A typical procedure would be to run a model under several deterministic scenarios, determine the best strategy under each scenario, and then concoct a mixed strategy from the results. This often produces suboptimal (not least cost) results. Try running the model with a deterministic low-load trajectory over the planning period and with a deterministic high-load trajectory over the planning period. You will find that the best “low strategy” is to install a single feeder with an optimal value of $2,739, the best “medium strategy” is to install a single substation with an optimal value of $3,382 and the best “high strategy” is to install a series of substations with an optimal value of $9,728. There is no way to deduce from these three scenario runs even an approximation to the actual least cost strategy, which is to “mix and match” S and F over time depending on load conditions. This is a general observation. In fact, given a single load trajectory, deterministic economic analysis will always select the same technology, based on size and cost, and repeat it as needed over the planning period. This is because the critical tradeoff in scenario analysis is between scale economy and cost of excess capacity. Learning and flexibility are ignored. Hence, no mixed strategy emerges from such an analysis.

A scenario planner might also suggest that we approximate the cost of the optimal strategy by weighting the three scenario costs with the relative probabilities of each scenario. How to specify the three scenario weights when in fact there are hundreds of potential future load paths is problematical. But, let’s give the planner the benefit of the doubt and weight the scenarios with the probabilities of all the future paths with loads similar to those in the three scenarios (this gives low, medium, high scenario probabilities of 0.5, 0.3, 0.2). The result is an expected value of $4,330. This is quite different than the actual expected cost of the optimal strategy, $3,547. In fact, there is no reason to expect the scenario planning approach to provide an accurate estimate in general. Most important, the scenario analysis does not provide information or insight about the actual least cost policy.

Two additional points should be made. First, the scenario approach makes it clear that, since the answer depends on the scenario analyzed, the optimal answer *must* depend both on the relative likelihoods of the different scenarios and on the potential for shifting from one scenario to another during the planning period. These shifts are captured in the description of the probabilistic behavior of load growth rates. Thus, there is no way to avoid a probabilistic analysis if one wants to determine the least-cost policy. Second, it is important to state that while deterministic scenario analysis is not useful for developing the optimal strategy, it can be useful in providing insights into how the model works and into the effects of different assumptions.

6
REAL UTILITY EXAMPLES

The data and results in this subsection are based on two actual utility case studies The first example is for General Power Company. General Power Company wants to develop and investment plan for the Teco substation area. The Teco area currently consists of one small and aging substation. Currently, load is growing about 1% per year but development is starting to take place. Peak load is close to existing capacity. Significant growth is likely to occur in the area some time in the next five to ten years. The extent and timing of that growth is very uncertain.

The General Power case illustrates how the model can be used to identify the scale and timing for infrastructure investments that minimize costs. It also illustrates the potential value of using modular technologies to defer large traditional investments when load growth is slow and uncertain.

The second example is for Blue Mountains Power. Blue Mountains provides electric distribution service to a remote ski area. Presently there is slow peak load growth (1/2 to 1 percent per year) in the area, but there is some chance of rapid growth if the ski corporation decides to implement business expansion plans. At some point in the future, the ski corporation plans to expand capacity by adding additional ski lifts and snow making equipment. The exact timing of the expansion is very uncertain.

The Blue Mountains case illustrates the value of a contingent expansion strategy composed of a smaller initial infrastructure investment followed by a larger investment if and when large load increases materialize. The example also illustrates the application of the Load Assessor software for describing and quantifying load growth uncertainty.

General Power Example

The alternatives for meeting future capacity needs in the area under study are to add a feeder from an adjacent substation or replace the existing substation with a new and larger substation. If the substation is added first, it will meet future capacity needs and the feeder will not be required. If the feeder is added first, the substation can be added later as load dictates the need for additional capacity.

As an alternative to both the substation and the feeder, small generators could be used to meet small increments in load and to defer the larger investments. Based on engineering and siting analysis, the General Power planners determined that as many as four distributed generators could be placed in the area. However, because of limits on where generators can be sited, each generator's effective unit capacity is lower than its nameplate capacity, and the cost per kilowatt increases as the generators are added.

The EPRI strategy model team worked with the utility to develop the model inputs and especially to create a characterization of the required load growth parameters (using the Load Assessor software as integrated into the Area Investment Strategy Model). The load behavior for the area tends to follow persistent trends. That is, when load is growing slowly, it tends to continue to grow slowly; and when growing at a rapid rate, it tends to continue to grow at that rate for a number of years.

Table 6-1 summarizes the planning assumptions required in the Area Investment Strategy Model for the General Power planning study. The reader is encouraged to formulate these cases using the model. Three illustrative cases are reported here. Case 1 assumes that the local generators, once installed, are not removed (salvaged) when the larger traditional investments are made. Cases 2 and 3 assume that the generators can be salvaged if removal makes economic sense. (The model permits the user to specify whether band-aids, in this case engines, are salvageable. See the Area Investment Strategy Model User Guide for further details.) Case 3 also assumes that there is no learning associated with the load uncertainty behavior. (The implications of this idea are briefly discussed below. For further explanation of the meaning of "no learning", see the "Learning" and "No Learning" cases reported in section 5, above.)

Table 6-2 shows the model inputs for cases 1 and 2.

Case 1 "No Salvage"

The least cost policy is shown in Table 6-3. When the engines are constrained to remain in place, the best policy is to install the substation now. This meets all potential future load that is anticipated for the area. This policy is not surprising given that the cost of the substation is $100 per kW while the engines cost a minimum of $500 per kW.

Case 2 "Salvage"

The least cost policy is shown in Table 6-4. E1 and E2 are engine investments, and T indicates that the end of the planning period has been reached. In this case engines can be removed when large capacity is added. The least cost policy is very different compared with case 1. Now, even though engines cost far more per kilowatt than either the substation or feeder, engines are part of the strategy. The fact that engines can be removed when the larger investment is made reduces the contribution of the installed engines to present value costs. It now makes sense to use the small modular investments to delay the traditional investments until load dictates that the larger investments are needed. It is also interesting that only two engines enter the optimal policy. This is due to two factors: (1) after the first two engines, the cost per kilowatt increases substantially and (2) compared with the feeder and substation alternatives, the capital cost per kilowatt of engines is relatively high. The engines are best used to delay large investments. Engines are not an economically efficient choice for providing large amounts of capacity.

Table 6-4 shows only part of the optimal policy. Details have been omitted because the optimal policy over the 12 year planning period has up to seven decision stages. The first four stages are shown here to illustrate the nature of the policy. The reader is encouraged to obtain the model, experiment with this case, and to explore the detailed results.

Table 6-1
Common Assumptions for General Power Study

COMMON ASSUMPTIONS FOR STUDY		
Time Horizon		12 years
Discount Rate		5.77%
Inflation Rate		4%
Accounting Method		Before Tax Cash Flow
Initial Peak Load		44,608 kW
Maximum Area Peal Load		70,000 kW
Load Saturation On-Set		60,000 kW
Salvage Value Specifications		
- Price of Capacity at Terminal Time		$10/kW-yr.
- Escalation of Price of Capacity		1.0
- Operating Cost of Capacity		$0/kWh
- Escalation of Operations Cost		1.0
- Final Load Growth Rate		1%
O&M Cost – S & F		$0.02/kWh
O&M Cost – Engines		$0.05/kWh
Avoided Energy Costs		$0.03/kWh
Emissions Rates & Costs		0
Load Shape	*Time (hrs)*	*% of Peak*
	0	100%
	88	95%
	264	90%
	8759	25%
	8760	0%
Load Growth Trends		
	Growth Rate	
Low	1.0%	
Medium	2.0%	
High	5.0%	

Table 6-2
Assumptions for Cases 1 & 2

ASSUMPTIONS – CASES 1 & 2			
Technologies	*Life*	*Size(kW)*	*Cost ($1000)*
S: Substation	40	20,000	$2,000
F: Feeder	30	6,000	$900
E1: Engine 1	30	3,000	$1,500
E2: Engine 2	30	1,500	$750
E3: Engine 3	30	3,000	$2,500
E4: Engine 4	30	3,000	$2,500
Trend Transition Probabilities			
	Low (1%)	*Medium (2%)*	*High (5%)*
Low (1%)	0.75	0.25	0.00
Medium (2%)	0.125	0.75	0.125
High (5%)	0.00	0.25	0.75
Initial Load Growth Rate		"Low" 1.0%	

Table 6-3
Least-Cost Strategy for Case 1: "No Salvage"

Decision (Stage 1)	**Chance**	**Decision (Stage 2)**
PV Cost = 5783.31		
S at t=0.00, L=44608	p=0.139, t=28.53, g=1.013	Terminate at t=12, L=52129
	p=0.576; t=20.14; g=1.018	Terminate at t=12; L=55623
	p=0.294; t=12.47; g=1.030	Terminate at t=12; L=63709

Table 6-4
Least-Cost Strategy for Case 2: "Salvage"

Decision(Stage 1)	Decision(Stage 2)	Decision(Stage 3)	Decision(Stage 4)
PV Cost 4797.14			
E1	E2	F(-E1, -E2)[1]	T
			E1
			E1
		S(-E1, -E2)	T
		S(-E1, -E2)	T
	E2	S(-E1, -E2)	T
		S(-E1, -E2)	T
		S(-E1, -E2)	T
	E2	S(-E1, -E2)	T
		S(-E1, -E2)	T
		F(-E1, -E2)	E1
			E1
			S

Case 3 "No Learning"

In cases where past observation of the load growth rate does not alter the assessment one would make about likelihood of any future load growth rate, no learning is possible. That is, the so-called "no learning" case assumes that the load growth in the next period is independent of the current growth rate. This means that one learns nothing about future growth rates by waiting to observe the present load growth rate. This behavior is modeled by changing the transition probabilities so that they are the same for all current (in this case, three) growth rates. Table 6-5 shows the transition probabilities assumed for this case.

[1] (-E1, -E2) means that the two engines are removed (salvaged) and replaced by the feeder and substation investments in stage 3. This allows the same engines to be used in subsequent stages.

Table 6-5
Assumptions for Case 3

ASSUMPTIONS – CASES 3			
Trend Transition Probabilities			
	Low (1%)	*Medium (2%)*	*High (5%)*
Low (1%)	0.125	0.75	0.125
Medium (2%)	0.125	0.75	0.125
High (5%)	0.125	0.75	0.125
Initial Load Growth Rate		“Low” 1.0%	

Table 6-6 summarizes the least cost policy. Here, as in the earlier, simple, no-learning case, as reported in Section 5, above, the optimal policy is independent of how load growth evolves. The best policy is to install engine 1, engine 2, and, when load growth exhausts the capacity of the two engines, salvage the engines and install the substation. Contrast this with the optimal policy in Table 6-4.

If trends in growth exist, such that learning is possible, you can develop polices that take advantage of the information provided by past observations of load growth. The resulting policies can, in some cases, have far lower costs.

Table 6-6
Least-Cost Strategy for Case 3: “No Learning”

Decision(Stage 1)	**Decision(Stage 2)**	**Decision(Stage 3)**	**Decision(Stage 4)**
PV Cost = 5320.41 E1	E2	S(-E1, -E2)	T

Blue Mountains Power Example

Electric load is growing very slowly in the area but the local distribution system is near capacity on peak use days. There is a winter afternoon peak driven by electric baseboard heat in vacation homes. Current capacity is about 34 MVA. Two sets of input assumptions drive the analysis results: future load uncertainty, and the capacity alternatives. These topics are discussed in the following two subsections.

Assessing Electric Load Uncertainty

The planners believe that some distribution capacity needs to be added very soon in order to respond to the planned expansion of the local ski area. It is important to note, however, that the expansion of the ski area has not yet begun. The ski area management claims that the first phase of their plans would add about 8 MVA load and the second phase would add another 4 MVA. The exact timing of the planned expansion is very uncertain.

The *Load Assessor Tool* was used to provide the load growth parameters required by the Area Investment Strategy Model. Since the expansion plans are uncertain, the load growth in the area is uncertain. The load growth parameters are selected such that the uncertainty is represented. The Load Assessor requires that the user provides answers to a series of questions about potential future load growth behavior. Based on the answers, the Load Assessor identifies a set of annual load growth rates and the chances for switching among the rates in any year. The chances of switching are captured in a set of transition probabilities, as illustrated in the cases above. The growth rates and probabilistic switching information is used by the Area Investment Strategy Model to describe the dynamic behavior of future load growth.

NOTE: The Load Assessor is a tool that is imbedded in the Area Investment Strategy Model. For a detailed explanation of the load assessor the user should read Area Investment Strategy Model, Version 1.5: User's Manual. Chapter 2 of the User's Manual describes all of the Load Assessor input screens and the basic mechanics of using the tool.

The load assessor has four input screens. The input variables and associated study assumptions are summarized in the Table 6-7.

Table 6-7
Summary of Load Assessor Data Screens

	Input Variable	**Study Assumption**
Screen 1	Current Load Current Growth Rate Forecast Period	34,000 kVA 0.5 % 12 Years
Screen 2	Load Growth Scenarios for the planning period.	Scenario 1 0.5% avg. growth Scenario 2 1.5% avg. growth Scenario 3 2.2% avg. growth
Screen 3	Growth rate holding times – average time that annual growth rates persist before shifting to higher or lower rates	Min. rate (0%) 2 yrs. Current rate (0.5.%) 5 yrs. Max. rate (25%) 1 yr.
Screen 4	Maximum Area Load – "Saturation" Saturation onset load level	55,000 kVA 40,000 kVA

Screen 1: Current peak load is 34,000 kVA and load is growing at about a half percent per year. The period over which load is to be predicted is 12 years.

Screen 2: Up to five scenarios are to describe future load growth behavior. These scenarios must be mutually exclusive descriptions of what can happen to load over the planning period. Each scenario must be described along four dimensions: the average growth rate over the entire planning period, the lowest possible growth rate in any year, the highest possible growth rate in any year, and the likelihood of the scenario actually occurring. The sum of the likelihoods must be 1.00. Three scenarios were used for this analysis: (1) the current slow load growth, 0.5 percent, continues through the planning period; (2) the first phase of the ski area expansion occurs sometime during the planning period, adding 8,000 kVA load; and (3) both phases of expansion occur adding 12,000 kVA load. Figure 6-1 shows the scenario input screen and related data.

Screen 3: One of the underlying assumptions in the Load Assessor is that load growth tends to follow trends. These trends are represented by assessing the likelihood of the persistence of the load growth rate in any year over the next several years. Screen 3 is used to record growth rate duration information. The duration of a load growth rate is often referred to as the holding time of the rate. Three durations must be provided: the average holding times for the minimum annual growth rate, for the maximum annual growth rate, and for the current growth rate.

Screen 4: The maximum area load is estimated to be about 55,000 kVA. This is load level when the area is completely built-out. Saturation onset is the point where load growth starts to slow due to build-out. For the study, saturation onset is 40,000 kVA.

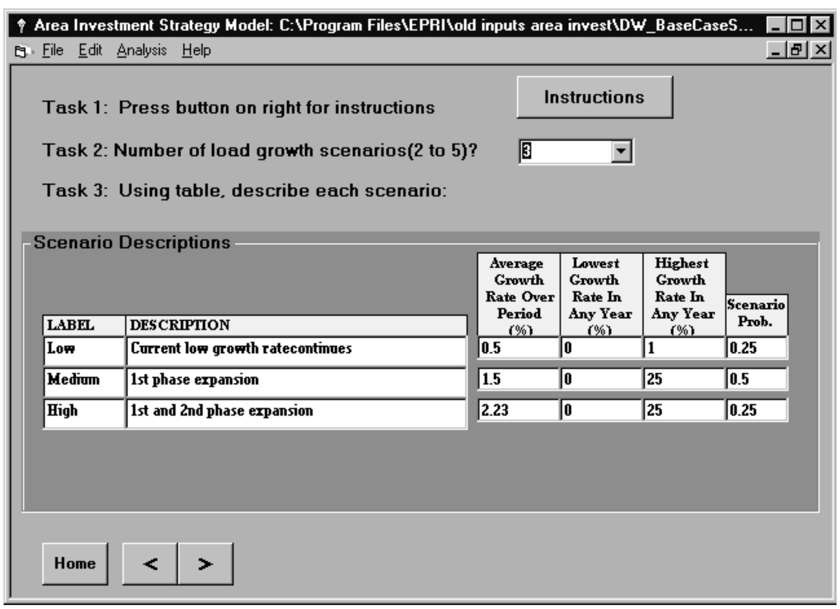

Figure 6-1
Load Assessor Scenario Input Screen

After the data are entered the Load Assessor is run to generate the growth trends and transition probabilities. The transition matrix that results from the above inputs is shown in Figure 6-3.

The growth rates and transition matrix that are found by the Load Assessor comprise a mathematical representation of the input data captured in the screens described above. The mathematical representation is selected to minimize the error between the forecasts provided by the scenarios and the forecasts provided by the mathematical representation. The mathematical representation is used in the Area Investment Strategy Model to determine the timing of the future investments.

The resulting forecast results can also be plotted, Figure 6-3. Most users will find the information provided in the plot sufficient to decide whether the load assessment captures the appropriate load uncertainty. If the uncertainty has not been captured, the answers to the questions in screens 1 through 4 can be changed, which will change the plotted results. This modification process can be repeated until the results are satisfactory.

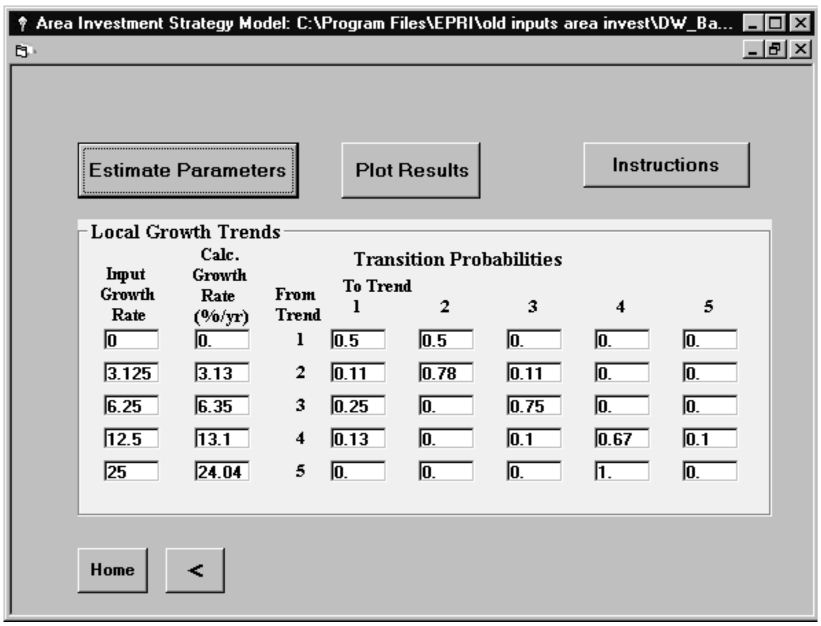

Figure 6-2
Load Assessor – Estimated Growth Rates & Transition Probabilities

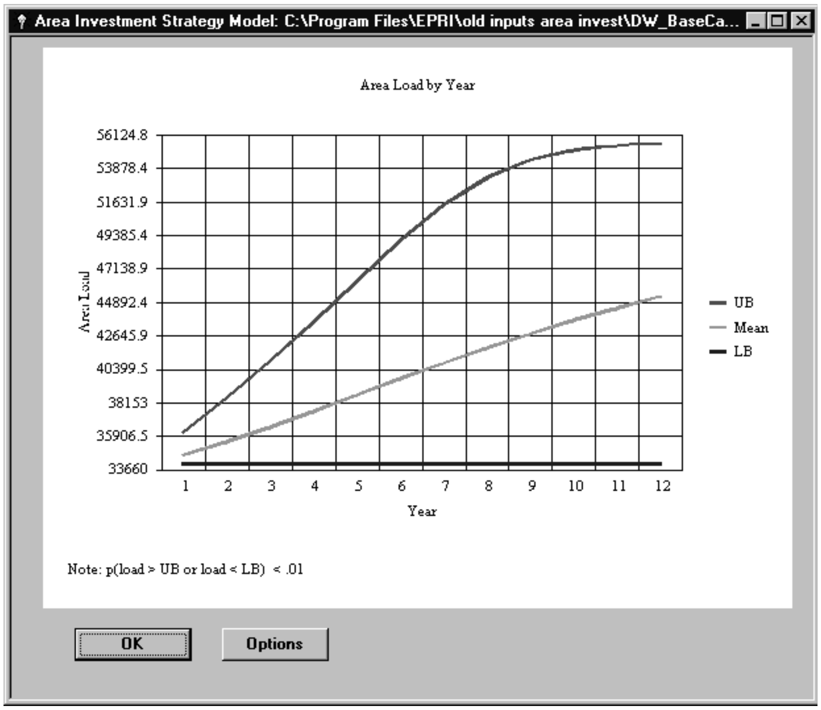

Figure 6-3
Load Assessor - Plot of Load Forecast

Capacity Alternatives

The company planning engineers identified four feasible capacity expansion alternatives:

1. DSM: Peak shaving DSM (converting baseboard heat to propane).
2. C0: A new circuit from a substation outside of the area (providing 8.5 MVA capacity)
3. C1T0: A short transmission circuit and a substation transformer (total capacity of 12 MVA)
4. GEN: Local generation.

Because the first phase of the ski area expansion could come in the next year, the planners believe that they must add at least 8 MVA capacity very soon. They can then wait and see what happens to load before making additional investments. Thus the feasible first year investments are to put in the new circuit (C0), or the transmission circuit and new transformer (C1T0), or 8MVA local generation. Because DSM cannot provide enough capacity to meet the first phase expansion, that alternative can only be used to fill needs that follow the initial investment.

There are capacity constrains in the existing circuits that limit local capacity to an increase of 13 MVA. Thus if C1T0 is installed after C0, the investment provides only an additional 5 MVA capacity. If C1T0 is installed after C0 it is designated as C1T0*.

Base Analysis

The commons assumption for the base case are shown in Table 6-8 through Table 6-10.

Table 6-8
Technology Parameters – Base Case

Technology	*Life*	*Size(kW)*	*Cost ($1000)*
DSM1: Load control program 1	30	1,060	$590.8
DSM2: Load control program 2	30	1,240	$689.3
DSM3: Load control program 3	30	1,240	$689.3
GEN: Local Generation	30	8,000	$6580
C0: New distribution circuit	50	8,000	$763.0
C1T0: New circuit and transformer pre C0	50	13,000	$3,611
C1T0 New Circuit & transformer post C0*	50	5,000	$3,611

Table 6-9
Growth Rates and Transition Probabilities – Base Case

	R1	*R2*	*R3*	*R4*	*R5*
R1 (0%)	0.50	0.50	0	0	0
R2 (3.13%)	0.11	0.78	0.11	0	0
R3 (6.35%)	0.25	0	0.75	0	0
R4 (13.10%)	0.13	0	0.10	0.67	0.10
R5 (24.04%)	0	0	0	1	0
Initial Load Growth Rate			“Low” 0.5%		

Table 6-10
Other Assumptions for Base Case

Time Horizon	12 years	
Discount Rate	5.0%	
Inflation Rate	2.6%	
Accounting Method	Before Tax Cash Flow	
Initial Peak Load	34,000 kW	
Maximum Area Peal Load	55,000 kW	
Load Saturation On-Set	40,000 kW	
Salvage Value Specifications		
- Price of Capacity at Terminal Time	$20/kW-yr.	
- Escalation of Price of Capacity	1.0	
- Operating Cost of Capacity	$0/kWh	
- Escalation of Operations Cost	1.0	
- Final Load Growth Rate	1%	
O&M Cost – T&D options	$0.0379/kWh	
O&M Cost – Engines	$0.05/kWh	
Avoided Energy Costs – DSM Options	$0.0379/kWh	
Emissions Rates & Costs	0	
Load Shape	*Time (hrs)*	*% of Peak*
	0	100%
	400	75%
	3500	35%
	8760	0%

The least cost first year investment is not surprising and illustrates the value of a contingent strategy. There are three first-year options: (1) local generation costing $6.6 million, (2) circuit and transformer costing $3.6 million, or (3) single circuit costing $0.8 million. The single circuit would appear to be the clear economic choice. In fact, by applying the Area Investment Strategy Model to the problem it is the best first year investment in a long-term least cost strategy. This strategy takes into account the relative costs of the investment alternatives and the potential future load growth trajectories.

There Table 6-11 shows the least cost strategy. In this case the distribution circuit is installed in year 1. The load control programs are then used to keep load below capacity. Only in the rapid load growth situation is the much more expensive distribution substation and feeder installed. Note that option C0 costs $95 per kW compared to between $590 and $690 for the DSM and over $700 per kW for the 5,000 kVA provided by C1T0*.

Table 6-11
Base Case Least Cost Policy

Decision (Stage 1)	Decision (Stage 2)	Decision (Stage 3)	Decision (Stage 4)	Decision (Stage 5)
PV Cost 4333.8				
C0	T			
	DSM1	T		
		T		
		DSM2	T	
			T	
			T	
	DSM1	T		
		DSM2	T	
			T	
			DSM3	T
				T
				C1T0*
		DSM2	T	
			DSM3	T
				T
				T
			DSM3	C1T0*

This clearly illustrates a contingent policy where the large investment is deferred as long as feasible.

Sensitivity Analysis

Several test cases were run varying the probabilities of the three scenarios. For example, the likelihood of occurrence of scenario 1 (no ski area expansion) was varied from .10 to .90. These variations had no effect on the least cost policy shown above. The average growth rates for each of the scenarios were also varied. Those variations also had no effect on the optimal policy.

Relaxing the constraint that at least 8,000 kVA must be installed in the first year does not make a difference in the policy. It is still best to install the distribution circuit first. Table 6-12 shows the present value and relative costs for various least cost strategies given alternative first year decisions.

Table 6-12
PV And Relative Costs of Strategies Based on Alternative First Year Decisions

First Year Decisions	PV Costs ($000)	Relative Costs
C0	4333.16	100.0
DSM1	4462.19	102.98
C1T0	6233.23	143.98
GEN	9438.58	217.82

The reader is encouraged to formulate and solve this case. It may be of some interest to change the transition matrix such that only one growth rate is possible over the entire planning period. This will occur if every row in the transition matrix consists of all zeroes but for a single element, which is set to 1. That same element must be 1 for all rows. The initial growth rate should also be set to that value. If that is done, then a deterministic case is simulated. The reader should find that it is quite impossible to take a collection of deterministic solutions that correspond to the scenarios in this problem and attempt to synthesize the actual contingent policy. This impossibility illustrates one of the pitfalls of scenario analysis noted in Section 5, above.

7
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A
APPENDIX—DATA

General Power Input Data

```
CASE TITLE: Real UtilityTest Case

CASE DESCRIPTION:
----------------
Base Case - with non-salvagale engines.


MISCELLANEOUS:
-------------
Time Horizon:   12
Discount Rate:   0.0577
Inflation Rate:  0.0400
Acccounting Method: Before Tax Cash Flow.


LOAD GROWTH SPECIFICATIONS:
--------------------------
NOTE: The growth rates may have been modified for use by the load model
Num  Trend   Growth Rate  Probability and Description
  1  LO         1.0100    0.750  0.250  0.000   Low Load Growth
  2  ME         1.0201    0.125  0.750  0.125   Medium Load Growth
  3  HI         1.0510    0.000  0.250  0.750   High Load Growth
      1.010    Initial Load Growth Trend
  44608.000    Initial Load (kW)
      1.010    Load Growth Base (computed for use in model)
Saturation effect included
 70000.000    Maximum Area Load
 60000.000    Saturation Onset Load (kW)


LOAD SHAPE:
-----------
Num     Time (hrs)  Pct of Peak
  1         0.0000     100.0000
  2        88.0000      95.0000
  3       264.0000      90.0000
  4      8759.0000      25.0000
  5      8760.0000       0.0000


ALTERNATIVES:
------------
Num  Alternative   Class                   Type                    Description
  1  S             Strategic               Load following          Substation
  2  F             Strategic               Load following          Feeder
  3  E1            Band-Aid                Non load following      Engine 1
  4  E2            Band-Aid                Non load following      Engine 2
  5  E3            Band-Aid                Non load following      Engine 3
  6  E4            Band-Aid                Non load following      Engine 4
Band Aids are not salvageable
```

Num	Alternative	Capacity	Capital ($000)	$/kW	Escalation	Lead Time	Life
1	S	20000.0	2000.0	100.0	1.000	0.0	40.0
2	F	6000.0	900.0	150.0	1.000	0.0	30.0
3	E1	3000.0	1500.0	500.0	1.000	0.0	30.0
4	E2	1500.0	750.0	500.0	1.000	0.0	30.0
5	E3	3000.0	2250.0	750.0	1.000	0.0	30.0
6	E4	3000.0	2500.0	833.3	1.000	0.0	30.0

O&M, GAS COST, HEAT-RATE, ETC.:

Num	Alternative	Fixed O&M	Gas Cost	Heat Rate	Variable O&M	System Energy
1	S	100.000	0.000	0.000	0.020	0.000
2	F	60.000	0.000	0.000	0.020	0.000
3	E1	40.000	0.000	0.000	0.050	0.030
4	E2	50.000	0.000	0.000	0.050	0.030
5	E3	60.000	0.000	0.000	0.050	0.030
6	E4	0.000	0.000	0.000	0.050	0.030

EMISSION RATES AND COSTS:

Num	Alternative	NOX Rate	SOX Rate	CO2 Rate	Other Rate
1	S	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
2	F	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
3	E1	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
4	E2	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
5	E3	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
6	E4	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000

Num	Alternative	NOX Cost	SOX Cost	CO2 Cost	Other Cost
1	S	0.000	0.000	0.000	0.000
2	F	0.000	0.000	0.000	0.000
3	E1	0.000	0.000	0.000	0.000
4	E2	0.000	0.000	0.000	0.000
5	E3	0.000	0.000	0.000	0.000
6	E4	0.000	0.000	0.000	0.000

LOSSES AND UNSERVED ENERGY:

For Plan: Substation

Load (kW)	Losses ($000)	Unserved Energy ($000)
44608	76.00	1.00
45724	79.00	1.00
46867	83.00	1.00
48038	87.00	1.00
49239	91.00	2.00
50470	95.00	2.00
51732	99.00	3.00
53025	104.00	4.00
54351	110.00	5.00
55710	115.00	6.00

For Plan: Feeder

Load (kW)	Losses ($000)	Unserved Energy ($000)
44608	91.00	0.00
45724	95.00	0.00
46867	100.00	0.00
48038	105.00	0.00
49239	110.00	15.00
50470	115.00	45.00

```
     51732      121.00                    100.00
     53025      126.00                    170.00
     54351      132.00                    250.00
     55710      140.00                    430.00


CUMULATIVE PERCENT LOSS REDUCTION:
----------------------------------
                Pre         S         F
E1             0.00      0.00      1.00
E2             0.00      0.00      1.00
E3             0.00      0.00      2.70
E4             0.00      0.00      2.70


CUMULATIVE PERCENT UNSERVED UNSERVED ENERGY REDUCTION:
------------------------------------------------------
                Pre         S         F
E1             0.00      0.00      0.00
E2             0.00      0.00      0.00
E3             0.00      0.00     67.00
E4             0.00      0.00     67.00


USER SPECIFIED CONSTRAINTS:
---------------------------
Num  Description
  1  Number of S    <= 1
  2  Number of F    <= 1
  3  F    Cannot follow:    S


AUTOMATICALLY GENERATED CONSTRAINTS:
------------------------------------
Num  Description
  4  Number of E1   <= 1
  5  Number of E2   <= 1
  6  Number of E3   <= 1
  7  Number of E4   <= 1
  8  E2   must be preceded by:   E1
  9  E3   must be preceded by:   E2
 10  E4   must be preceded by:   E3


TERMINAL VALUE SPECIFICATIONS:
-----------------------------
Uses Cost-to-Go
     10.000   Price of Capacity at Terminal Time
      1.000   Escalation on Price of Capacity at Terminal Time
      0.000   Operating Cost at Terminal Time
      1.000   Escalation on Operating Cost at Terminal Time
      1.010   Future final growth rate
NOTE: This option assumes that the business continues indefinitely
```

Blue Mountains Power Input Data

```
CASE TITLE: Blue Mountain Power Base Case

CASE DESCRIPTION:
----------------
Base Case

All options with Base Case
Assumptions.  Salvage value based on
```

```
Cost-to-Go.
No Saturation
Only DSM-heavy
at Dover available as bandaids.


MISCELLANEOUS:
-------------
Time Horizon:   12
Discount Rate:   0.0500
Inflation Rate:  0.0260
Acccounting Method: Before Tax Cash Flow.


LOAD GROWTH SPECIFICATIONS:
--------------------------
NOTE: The growth rates may have been modified for use by the load model
Num  Trend   Growth Rate  Probability and Description
  1  A          1.0000    0.500  0.500  0.000  0.000  0.000   0% annual
  2  B          1.0313    0.110  0.780  0.110  0.000  0.000   3% annual
  3  C          1.0636    0.250  0.000  0.750  0.000  0.000   6% annual
  4  D          1.1312    0.130  0.000  0.100  0.670  0.100   13% annual
  5  E          1.2408    0.000  0.000  0.000  1.000  0.000   24% annual
      1.005    Initial Load Growth Trend
  34000.000    Initial Load (kW)
      1.031    Load Growth Base (computed for use in model)
Saturation effect included
 55000.000    Maximum Area Load
 40000.000    Saturation Onset Load (kW)


LOAD SHAPE:
-----------
Num     Time (hrs)  Pct of Peak
  1         0.0000     100.0000
  2       400.0000      75.0000
  3      3500.0000      35.0000
  4      8760.0000       0.0000


ALTERNATIVES:
------------
Num  Alternative   Class                   Type                     Description
  1  DSM1          Band-Aid                Non load following DSM   DSM1-HEAVY
  2  DSM2          Band-Aid                Non load following DSM   DSM2-HEAVY
  3  DSM3          Band-Aid                Non load following DSM   DSM3-HEAVY
  4  C0            Strategic               Load following           DC1:  New 90G5 Distribution
Circuit
  5  C1T0          Strategic               Load following           S1D2: New Sub & Circuit at
Mt. Snow
  6  C1T0*         Strategic               Load following           S1D2*: Less Cap if Added
after DC1
  7  GEN           Strategic               Non load following       Local CT
Band Aids are not salvageable

Num  Alternative     Capacity   Capital ($000)          $/kW   Escalation    Lead Time    Life
  1  DSM1              1060.0            590.8         557.4        1.000          0.0    30.0
  2  DSM2              1240.0            689.3         555.9        1.000          0.0    30.0
  3  DSM3              1240.0            689.3         555.9        1.000          0.0    30.0
  4  C0                8000.0            763.0          95.4        1.000          0.0    50.0
  5  C1T0             13000.0           3611.0         277.8        1.000          1.0    50.0
  6  C1T0*             5000.0           3611.0         722.2        1.000          1.0    50.0
  7  GEN               8000.0           6580.0         822.5        1.000          0.0    30.0
```

O&M, GAS COST, HEAT-RATE, ETC.:

Num	Alternative	Fixed O&M	Gas Cost	Heat Rate	Variable O&M	System Energy
1	DSM1	0.000	0.000	0.000	0.000	0.038
2	DSM2	0.000	0.000	0.000	0.000	0.038
3	DSM3	0.000	0.000	0.000	0.000	0.038
4	C0	0.000	0.000	0.000	0.038	0.000
5	C1T0	0.000	0.000	0.000	0.038	0.000
6	C1T0*	0.000	0.000	0.000	0.038	0.000
7	GEN	0.000	0.000	0.000	0.050	0.038

EMISSION RATES AND COSTS:

Num	Alternative	NOX Rate	SOX Rate	CO2 Rate	Other Rate
1	DSM1	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
2	DSM2	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
3	DSM3	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
4	C0	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
5	C1T0	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
6	C1T0*	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000
7	GEN	0.0000e+000	0.0000e+000	0.0000e+000	0.0000e+000

Num	Alternative	NOX Cost	SOX Cost	CO2 Cost	Other Cost
1	DSM1	0.000	0.000	0.000	0.000
2	DSM2	0.000	0.000	0.000	0.000
3	DSM3	0.000	0.000	0.000	0.000
4	C0	0.000	0.000	0.000	0.000
5	C1T0	0.000	0.000	0.000	0.000
6	C1T0*	0.000	0.000	0.000	0.000
7	GEN	0.000	0.000	0.000	0.000

CUMULATIVE PERCENT LOSS REDUCTION:

	Pre	C0	C1T0	C1T0*	GEN
DSM1	0.00	0.00	0.00	0.00	0.00
DSM2	0.00	0.00	0.00	0.00	0.00
DSM3	0.00	0.00	0.00	0.00	0.00

CUMULATIVE PERCENT UNSERVED UNSERVED ENERGY REDUCTION:

	Pre	C0	C1T0	C1T0*	GEN
DSM1	0.00	0.00	0.00	0.00	0.00
DSM2	0.00	0.00	0.00	0.00	0.00
DSM3	0.00	0.00	0.00	0.00	0.00

USER SPECIFIED CONSTRAINTS:

Num	Description
1	Cannot have: C1T0 and C0
2	Cannot have: C1T0 and C1T0*
3	C1T0* must be preceded by: C0
4	DSM1 must be preceded by: C0 or C1T0
5	Number of C0 <= 1
6	Number of C1T0 <= 1
7	Number of C1T0* <= 1

```
AUTOMATICALLY GENERATED CONSTRAINTS:
------------------------------------
Num  Description
  8  Number of DSM1 <= 1
  9  Number of DSM2 <= 1
 10  Number of DSM3 <= 1
 11  DSM2 must be preceded by: DSM1
 12  DSM3 must be preceded by: DSM2


TERMINAL VALUE SPECIFICATIONS:
-----------------------------
Uses Cost-to-Go
     20.000   Price of Capacity at Terminal Time
      1.000   Escalation on Price of Capacity at Terminal Time
      0.000   Operating Cost at Terminal Time
      1.000   Escalation on Operating Cost at Terminal Time
      1.010   Future final growth rate

NOTE: This option assumes that the business continues indefinitely
```