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Full Value Estimation of Electric Utility Options

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ABSTRACT

Utility planning has evolved to meet regulatory requirements, based upon the costs of individual technologies and complicated by successive issues including DSM, NUGs, and environmental externalities. Additional sources of value exist, based on how options interact with the existing power system, but have not been generally recognized or evenly applied for planning.

This thesis constructs a framework for comprehensively identifying utility options and values. It shows how component values can be analyzed independent of option technologies by using the subset of option and system characteristics relevant to each component value. Sensitivity analysis of these characteristics allows construction of component value supply curves. Component values related to dispatch, transmission and distribution, reliability and quality, financial risk, and environmental costs are identified and discussed.

Five specific component values were chosen to illustrate the thesis methodology, based on system reserve margin, unit size, storage for non-dispatchable resources, system spinning reserve, and thermal dispatch constraints. These were analyzed for the New England region using three different types of production cost models. An original algorithm was implemented for the optimal use of storage with wind and solar generation.

Results range from small to significant. System reserve margin and unit size for some nuclear technologies can be worth as much as 910 and 365 1995 $/kW respectively. Other component values may be as large, especially those related to specific network location.

This thesis concludes that utility planning can be significantly improved by considering a wider range of utility options and adding as many component values as possible to traditional levelized cost. Increased competition will make component values even more valuable, as deregulated generation has increased incentives to consider all sources of value and revised regulation of T&D requires consideration of component values to create the correct structures and incentives.

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This thesis would not have been possible without my father Dr. William Schenler and grandfather Henry Schenler, who provided not only the opportunity, but also the inspiration and the high standards which this thesis attempts to meet.

Finally, this thesis is dedicated to my wife and partner Sue, whose patience and motivation in abundant and equal measure helped to make it possible.

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1.0 Introduction

Planning for the future of the electric utility sector is an important and complex problem. This sector is a complicated system with many players that have a large range of options open to them, and the societal goals that the industry must aim to achieve have multiple objectives and are subject to intense debate. All planning must consider the impact of uncertainties in demand, fuel prices, technological price and availability, and industry structure, to name just a few.

In this context, the question of what constitutes value to utilities and to society is an important one. How to evaluate and compare utility planning options fairly and evenly depends upon recognizing value from many different sources. At one time, demand growth was relatively predictable and the primary basis for planning was the cost of new generation capacity. Today value can be ascribed to many different aspects of utility operation, including generation, transmission and consumption. The problem is that not all possible sources of value are generally recognized and used in planning, and that those values which are recognized may be unevenly applied or claimed to favor one option over another. Identification of individual sources of value in specific market niches is important, but the real need is for a comprehensive system to identify and evaluate the full range of possible values.

This thesis looks at the question of what constitutes value in electric utility planning, so that as many different kinds of options as possible can be compared on a level playing field both for vertically integrated utilities and for individual organizations under coming scenarios of competition and dis-integration. Sources of value have been comprehensively surveyed based on 1) the sequential series of utility functions from generation to customer end uses, and 2) the full range of time scales related to different planning needs. Based on this survey, a range of individual or component values have been identified and classified within a coherent framework. In order to separate the analysis of these component values from the individual options that can provide them, key subsets of option and system characteristics are identified. Value supply curves based on these characteristics are then proposed, so that any option which can supply a component value can be evaluated without individually modeling it. A subset of the component values identified has been chosen to illustrate this methodology, and modeled using two production cost models and an original optimization model to produce supply cost curves.

This thesis is aimed at the community concerned with long range, strategic electric utility planning, including utilities, independent generators, regulators, and concerned intervenors (customers, environmentalists, etc.). As the industry is in the process of rapid change, the thesis methodology addresses how component values are affected by industry structure. In general, component values exist independent of industry structure, but under competition and dis-integration market players and incentives are emerging that can change these values from implicit and internal planning considerations to explicit market price signals.

This chapter introduces the importance and complexity of electric utility planning, discusses the needs and opportunities in current planning methods, and outlines the proposed framework for full value estimation. Later chapters survey the history of value in utility planning, introduce the full valuation framework comprehensively and discuss the range of individual values. The methodology is then applied to a subset of sample component values, and the results and conclusions are presented.

1.1 Importance of Utility Planning

The importance of planning in the electric utility sector is of course directly tied to the size and importance of this sector in our economy and society. The most direct and gross measures of this importance can be shown by the relative amount of capital or infrastructure and annual income for this sector versus others. Statistics for 1993 show that the US utility sector is the industry with the single largest gross stock of fixed private capital, equal to 991 billion dollars. This is more than all fixed private capital for the transportation industry ($636 billion), almost half of all manufacturing industries ($2,347 billion), and 5.2% of all fixed private capital in the US

($19,090 billion)[1]. Gross revenues of the US electric sector were 187 billion dollars in 1992 for 2735 TWh sold at an average price of 6.8 ¢/kWh. This can be compared to expenditures of $222 billion for petroleum products and $473 billion for all major energy sources[2].

The importance of the electric utility sector is not grasped by just sheer size. In a less quantifiable but more direct fashion, we are all intimately acquainted with its importance by the ubiquity of electricity in our daily lives. We do not directly consume kWh of electricity, but its myriad secondary services surround us with heat, light, mechanical power and communications, to name just a few.

Planning for the utility sector is important not only because of its size, but because the impacts of planning decisions last a long time. Although regulatory changes are shifting the market structure rapidly, the sheer scale of the capital investment and the long life of individual units of physical infrastructure means that the physical system has a large resistance to change. Even the most attractive new technology or resource at the most optimistic market penetration rate requires significant time to make a large impact. This means that planning must have a long time horizon, and that consequences may endure for 30 to 40 years or even longer.

1.2 Complexity of Utility Systems and Planning

Apart from the sheer size and longevity of the physical system, there are also a range of physical reasons for complex system behavior. The sources of this complexity include the following.

- Electricity as a Secondary Good - People do not consume electricity directly, but instead use it to provide the many services they desire. As one well known analyst has said, people don't want electricity, they want hot water and cold beer.. Utilities have come to recognize that they sell these services, and not just kWh, and that DSM may provide

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1 U.S. Bureau of Economic Analysis, *Survey of Current Business*, August 1994.
2 U.S. Energy Information Administration, *State Energy Price and Expenditure Report*, annual.

more efficient ways to provide such service. The true source of value is to provide a lower price or more service to the customer, including energy, reliability and power quality

- The Load Curve - Electricity cannot be directly stored, and indirect storage (in the form of pumped hydro, pressurized air, or batteries) is limited, so supply must meet demand instant by instant as it varies through daily and annual cycles. This implies the need for a range from base to peak load generation with different balances of fixed and variable costs. This in turn implies that cost of supplying electricity varies with total load, and hence by time of day and year.

- Technological Diversity - Existing systems are composed of a wide range of generating technologies, and the mix of technologies can vary widely between utilities. Each unit has its own set of characteristics which are required for planning, including capital cost, fuel cost, heat rate (efficiency), maintenance costs and time requirements, forced outage rate, type of fuel, ramping rate, etc..

- Network Flow - Electricity is not dispatched directly from generator to consumer, but instead flows across a transmission and distribution network according to physical laws. These laws restrict system dispatch and operation, so that safety limits are reached sooner than they would be under switched flow for both normal and failure contingency conditions.

- Non-Homogeneity - The cost of supplying electricity to customers varies over the utility network by both space and time, based on the load curve and network flow. This non-homogeneity complicates both utility pricing, and utility planning for new options.

- Uncertainty - The uncertainty in future predictions necessary for planning includes load growth rates, fuel prices, capital costs, O&M costs, discount rates, and many other assumptions. Planning for a single predicted future is a guarantee of failure, because "the forecast is always wrong." Planning needs to consider not just possible sensitivity cases, but the values of robust options and flexibility in planning.

- Environmental Externalities - The costs of pollution are not included in the price of electricity. This pollution includes chiefly air emissions, but also solids like flyash, water pollution leaching from mines, and thermal pollution. Utilities must plan to meet regulations designed to limit externalities (e.g. emissions 'bubbles' and emissions trading markets), based on the best and reasonably available control technologies, the costs of environmental damage, and the lowest emissions reduction costs and strategies.

Finally, there is a time spectrum associated with utility planning due to the physical requirements of operation and construction. At the low end of this time scale is short term operation and dispatch planning, based on network safety and demand considerations. As the time horizon increases, planning includes economic dispatch, maintenance scheduling, fuel purchase planning, individual unit commitments and strategic planning. This time scale can thus range from less than a second to over 20 years, or almost 9 orders of magnitude, as shown in Figure 1.1[3] below.

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3 Fernando, C., P. Kleindorfer, R. Tabors, F. Pickel, and S. Robinson, *Unbundling the US Electric Power Industry: A Blueprint for Change*, March 1995

Figure 1.1 - Electric System Planning Time Line

TIME	PLANNING NEEDS
Decades/Years	Forecasting & Construction
Years/Months	Maintenance
Days	Scheduling
Hours	Unit Commitment
Minutes, 15 - 5	Dispatch
5 - 1	Spinning Reserve
Seconds, < 10	Frequency Control Voltage Control/Dynamics
Cycles, 100	Transient Stability

The point to this figure is not just that planning must cover a wide range of time horizons, but that decisions made on one end of the time scale can affect subsequent options and decisions on the other end of the scale. For example, the choice of a dispatch or spinning reserve rule may affect the choice of new generation options, while the purchase of new equipment (e.g. static VAR compensators or switching tap transformers for phase shifting) may affect system stability and control dynamics. This means that there may be strategic planning value in options that affect operation over very short time periods.

The physical size and operation of the utility system are not the only sources of complexity that must be considered in utility planning. The financial and regulatory structures of the industry are not only diverse and complex, but also changing rapidly. Both of these factors are extremely relevant to the question of what constitutes value in planning, because the financial structure indicates the number and size of the different participants in the marketplace, and the regulatory structure determines the objectives and rules by which the participants interact.

Electric utilities in the US are primarily investor owned, generating 2271 TWh or 78.8% of total generation which was 2883 TWh in 1993[4]. Publicly owned utilities range from municipal utilities with 3.6% of total generation to rural electricity coops(8.0%) to federal interstate entities like the Tennessee Valley Authority and the Bonneville Power Administration(9.6%). Current generation ownership also includes non-utility generators and independent power producers, with 60.8 GW of capacity and 325 TWh of generation in 1993. In other countries, the range of ownership is similar, with the addition of nationally owned utilities.

Industry dis-integration will further increase this complex cast of participants. Not only will the generation, transmission and distribution functions be separated under current plans into different entities, but the marketplace will also be complicated by independent system operators, independent power brokers, spot and futures markets, and increased mergers as competition drives advantageous associations. Only a common concept of what constitutes value can drive markets to recognize and price different aspects of providing electrical services.

The regulatory process is important to good planning, because it provides the rules of the game. Good planning is complex because the rules are complex, and the rules are complex because they come from all levels of government from local municipalities up to federal agencies. The primary source of regulation has traditionally been at the state level in the form of the regulatory compact, where the utility is granted the opportunity to earn a regulated rate of return on its rate base in return for providing a service which is a natural monopoly. Both the security of the rate of return and the monopoly aspects of this compact have been subject to considerable erosion in recent years, but they still form the fundamental basis of current utility regulation. On top of this foundation, state or local regulation covers the siting of generating plants and transmission lines, pollution control, and

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4 US Energy Information Administration, *Annual Energy Review*. 1994.

public safety. Federal regulation is primarily based on the constitutional power to regulate interstate commerce. This clearly includes interstate power transactions, but has also been interpreted to include air pollution based on interstate transport of emissions. Additional regulatory control is based on the protection of public safety, especially in the area of nuclear safety standards.

The regulatory process is important, because the primary objective of utilities has been to maximize profits to private investors or minimize costs to public owners, subject to the constraints of regulatory process. The historical utility planning paradigm in the US has been dominated by investor owned utilities under state regulation. Therefore utility planning has evolved to meet the standards required for rate cases and other regulatory hearings. More recent steps in this evolution have included consideration of demand side management, bidding by NUGs and IPPs, emissions adders, and options contracts.

Deregulation should actually simplify the regulatory process by limiting monopoly control to the transmission and distribution functions. New regulations are required for pricing transmission and some ancillary services related primarily to system security, but by removing regulation of the generation function the regulatory process will be simpler overall. It will also be more consistent from state to state because all generators will have the same competitive incentives. These incentives will reward companies for planning that considers any and all sources of value, whether they are buyers or sellers.

1.3 The Planning Problem

Utility planning has evolved to meet the evolving requirements of state regulatory agencies. If the process for structuring, submitting and approving utility plans does not include some source of value then it will be ignored in utility decision making and actions. The following list includes some of the deficiencies in current planning practice.

- First, the basic incentives or rate structures of the regulatory process may distort utility planning and operation from the most economically efficient alternatives. For example, if investment in ratebase is rewarded and fuel price increases are passed through to customer through fuel clauses it is not clear whether the optimum capital to fuel cost balance will be chosen. Other examples include rate structures for different classes which may conflict with DSM goals, and environmental externality adders which may not lead to least cost emissions reductions.

- Second and more fundamental the decision criterion (usually levelized cost) may not include all possible sources of value. Utilities have incorporated DSM and environmental externalities into integrated resource planning or least cost utility planning, but other sources of value such as spot pricing or T&D pricing are usually omitted.

- Third, the range of options considered may not be complete as a result either of the solicitation or selection process. Utility options include the entire range of anything the utility can do to meet future demand for services supplied by electricity. This means that options can include not only new kinds of generation, but also transmission and distribution alternatives, demand side management or other service-related alternatives, and different policies for system operation like fuel switching or emissions trading or taxes.

- Fourth, the emphasis is on the competition between individual options and not upon how they interact with the existing system. For example, emissions will generally be based upon an assumed capacity factor rather than system modeling. Incorporating emissions adders with sometimes dubious economic bases into the levelized cost will shift the selection toward cleaner generators, but unless the plants are dispatched with the same adders this does not guarantee the most efficient way to reduce pollution.

- Fifth, state regulations can vary significantly from state to state, including what goes into rate base, what the rate of return is, and how

DSM, bidding, and many other issues are handled[5]. This means that different states may have incentives for different types or levels of efficiency. In addition as interstate mergers and wheeling contracts become more common, there may be inefficiencies in investment allocation between states.

Of this list, the first and fifth problems will be basically solved as competitive incentives replace regulatory incentives nationally. Problems two through four are more basic. A number of recent and continuing trends in the electric utility sector illustrate how new options, system interactions and values not included in conventional average or levelized cost can be significant. Some of these new sources of value include;

- Spot Pricing or Real Time Pricing - The importance of the time dependent marginal cost of electricity is generally well accepted, but in most regulatory venues, it is used either for selecting between utility options, or for electricity pricing in a limited fashion. If spot pricing is used for planning, and ignored in operation this may eliminate the advantages of the option selected.

- Unit Size - The use of many small generation units at a single site may yield benefits in both reliability and maintenance, which are easy to recognize but generally not incorporated in planning.

- Option Flexibility - The ability to choose flexible options that can adapt to future shifts in load growth or fuel prices can have significant value in the face of uncertainty. Example can include early site purchase for later construction of generation, or use of combustion turbines that can be switched to coal gas.

- Dispatchability - Whether or not a generation or DSM option can be controlled by system operators affects its value. The value of non-dispatchable options may depend on both their time correlation to system demand and the total system fraction of non-dispatchable capacity.

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5 NationalAssociation of Regulatory Utility Commissioners, *Utility Regulatory Policy in the United States and Canada, Compilation 1993-1994.*

- Transmission & Distribution - The value of reducing the need for T&D maintenance, replacement, and new construction is well recognized, but rarely if ever used in strategic utility planning.

- Reliability - The value of reliable service is easy to recognize, and the damage costs of unreliable service have been estimated, but the marginal cost and marginal benefit have no market and are not currently used for planning.

- Emissions - Utility air pollution may be valued by the cost of control technologies, the cost of damages, the least cost to reduce, or the market value under emissions trading. Any one (or none) of these values may be used in utility planning or operation, depending upon the local regulatory regime.

This list of examples is by no means complete, but it is certainly long enough to show that there are many sources of utility value that are either unevenly applied or uncommonly recognized. In some cases, these values may be recognized or applied in planning, but not in operation, while in other cases the reverse is true. In either case, the planning decision reached can be less than optimum. Sometimes these values are claimed in order to make an individual option more competitive, but they are not generally applied across the board to all options. For example, photovoltaic generation can claim credits for reducing T&D losses and reducing or deferring T&D capital costs, but these benefits are not always given to other forms of distributed generation.

It is worth understanding that most (if not all) of these sources of value exist independent of the industry structure, but that industry structure may make them easier or harder to recognize, evaluate or include in planning and decision making. For example, the value of some characteristics affecting dispatch (like a short startup period) may be incorporated implicitly by experienced planners within a monopolistic utility, but this value may be lost in a dis-integrated industry unless an appropriate price signal is attached to it and passed between participants. Conversely, some values (like reliability or dispatchability) may be difficult to price under a monopolistic structure, but may be priced directly by competition in a deregulated industry with a market for the appropriate transactions. Most of these values exist independent of market structures (as cost savings), but some cannot be obtained unless electric services are unbundled. In either case, market structures should attempt to recognize and incorporate them. Most unconventional option values result from the interaction between the existing utility system and whatever new option is considered. It is a more subtle consideration whether such values still exist if and when the system has been disaggregated into a market of many individual participants that are not centrally dispatched or coordinated. This thesis contends that such values may endure in spite of such disaggregation, but that to obtain their benefits correct price signals will be needed.

While recognizing and applying any and all recognizable sources of value is an improvement, the point is that for good decision making all available sources of value for each available option need to be compared in an equitable way, so that options compete on a level playing field. What is needed, and what this thesis supplies, is an organized way of identifying all possible utility options and sources of utility value and to show how these values can be quantified and compared.

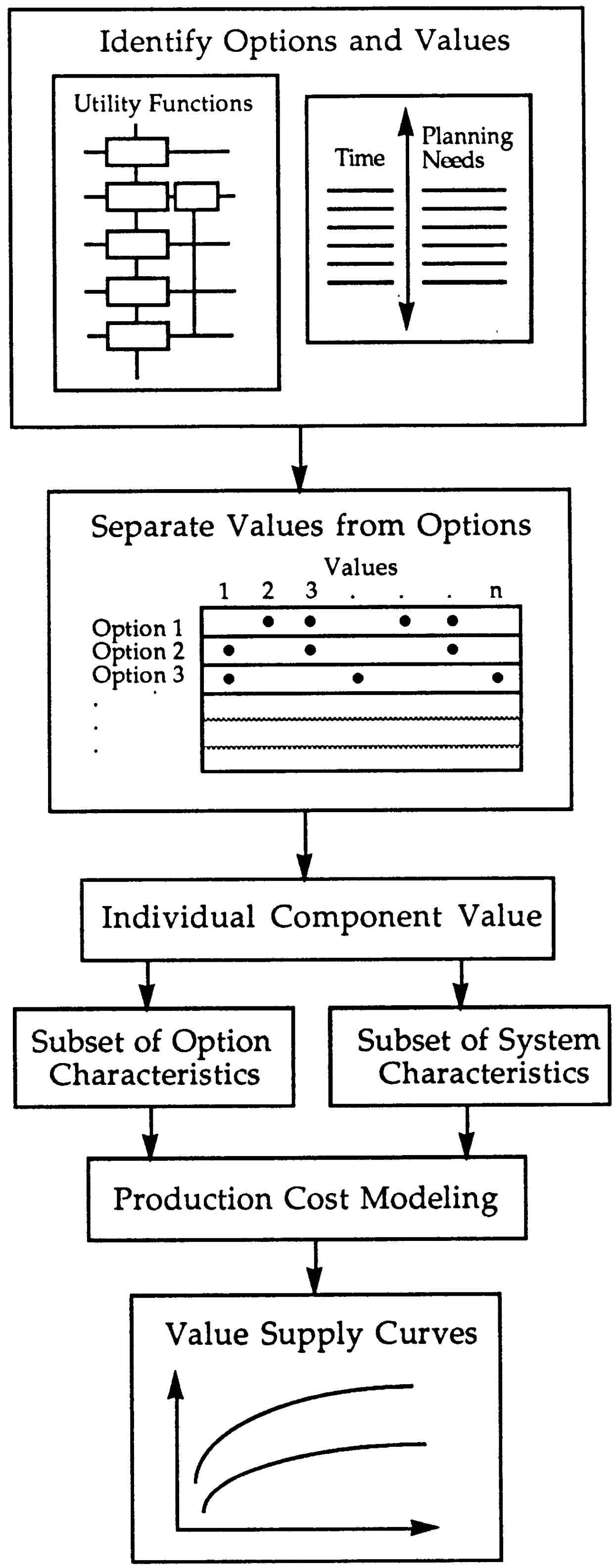
1.4 Thesis Outline and Methodology

Given the importance, complexity and difficulties associated with electric utility planning, what is needed for a more comprehensive view of utility planning? First, it is necessary to have a more comprehensive economic theory of value, recognizing all the savings or services for which utilities, their customers, and new participants in a competitive marketplace will be willing to pay. Utility planning is a multi-attribute problem with uncertainty, so multi-attribute utility theory and financial options theory are important planning tools, but this thesis does not focus on these two issues. Instead it concentrates on taking a comprehensive view of the individual aspects of utility options that have (or may have under competition) a direct monetary value. Because these individual sources of value can be added to each other and to conventional levelized cost they are called *component* *values* throughout this thesis[6]. Second, there needs to be a framework to search for and to identify such individual values in a comprehensive way. Third, there needs to be a way to analyze separate individual utility values in a generic way, so that they can be applied to all options which can claim them. Fourth, there needs to be quantitative proof of steps of the generic individual values identified. Finally, there is a need to show how these generic values can be applied to allow a wide range of utility options to compete on a more level playing field as the sector moves to a competitive structure.

This thesis proposes a methodology that will meet these needs by using a series of steps that are show in Figure 1.2 below.

6 In prior presentations of this thesis material, component values have also been called niche values because the sources of these values are found in different market niches.

Figure 1.2 - Overview of Thesis Methodology



The question of what constitutes value in electric utility service is discussed first in Chapter 2 of this thesis. The framework established for identifying the whole range of utility options and individual sources of value is shown in the first box above, using the utility functions and time frames relevant to utility planning as shown in Figures 1.1 and 2.1. Chapter 2 then discusses the theoretical separation of options and values as shown in the second box, and then discusses how individual component values can be analyzed by identifying and using the relevant subsets of option and system characteristics for production cost modeling. By varying the parametric values of these characteristics, supply curves for each individual component value are established as shown, so that the overall system cost or benefit associated with different levels of the individual value can be read off and applied to other appropriate options. Chapter 3 then classifies and discusses the individual component values identified. Chapter 4 takes a subset of these values chosen to demonstrate the methodology quantitatively, and discusses the scenarios, assumptions, and modeling methods used to analyze them. Chapter 5 then discusses the results for these values and compares their relative size, and Chapter 6 draws the overall conclusions.

2.0 Theory of Full Value Planning

This chapter describes the theory of the thesis methodology which attempts to remedy the deficiencies in comprehensive identification of utility options and values, and the lack of consideration of the interaction between utility options and the systems in which they are placed. It defines the terms used in the methodology, and proposes a framework for the comprehensive identification of utility options and values. It then discusses how a range of component values can be analyzed based on option and system characteristics. The concept of component values is then extended to include value supply curves through variations in the option and system characteristics. The range of component values identified is discussed individually in Chapter 3, including the source and scale of value, existing theory and models, and which present or potential planners should use them.

2.1 Definition of Terms

For the purposes of this thesis it is useful to define the following terms.

- Utility option - In the context of this thesis, a utility option is any planning choice which the utility may implement to meet customer demands for electrical services. This includes traditional supply side options that generate, store or transmit electricity, and more recently accepted demand side options that shift or reduce the electricity required to provide services. Other non-technological options may include system operation choices like dispatch policies, financial structures like fuel or power purchases, or rate structures like real time pricing.

- Component value - This term is used to indicate any single source of value available to a utility or its customers. Traditional planning value (i.e. levelized cost per kWh generated or saved by a technology) could be considered the first of many component values, but in this thesis the term refers especially to those values not currently included in utility planning or regulation. While a component value may be based on multiple attributes, in this thesis a component value is monetary and may be either positive or negative.

- Full value estimation - Full value estimation is an evaluation of utility options which is based on summing all available component values, including conventional values and new component values.

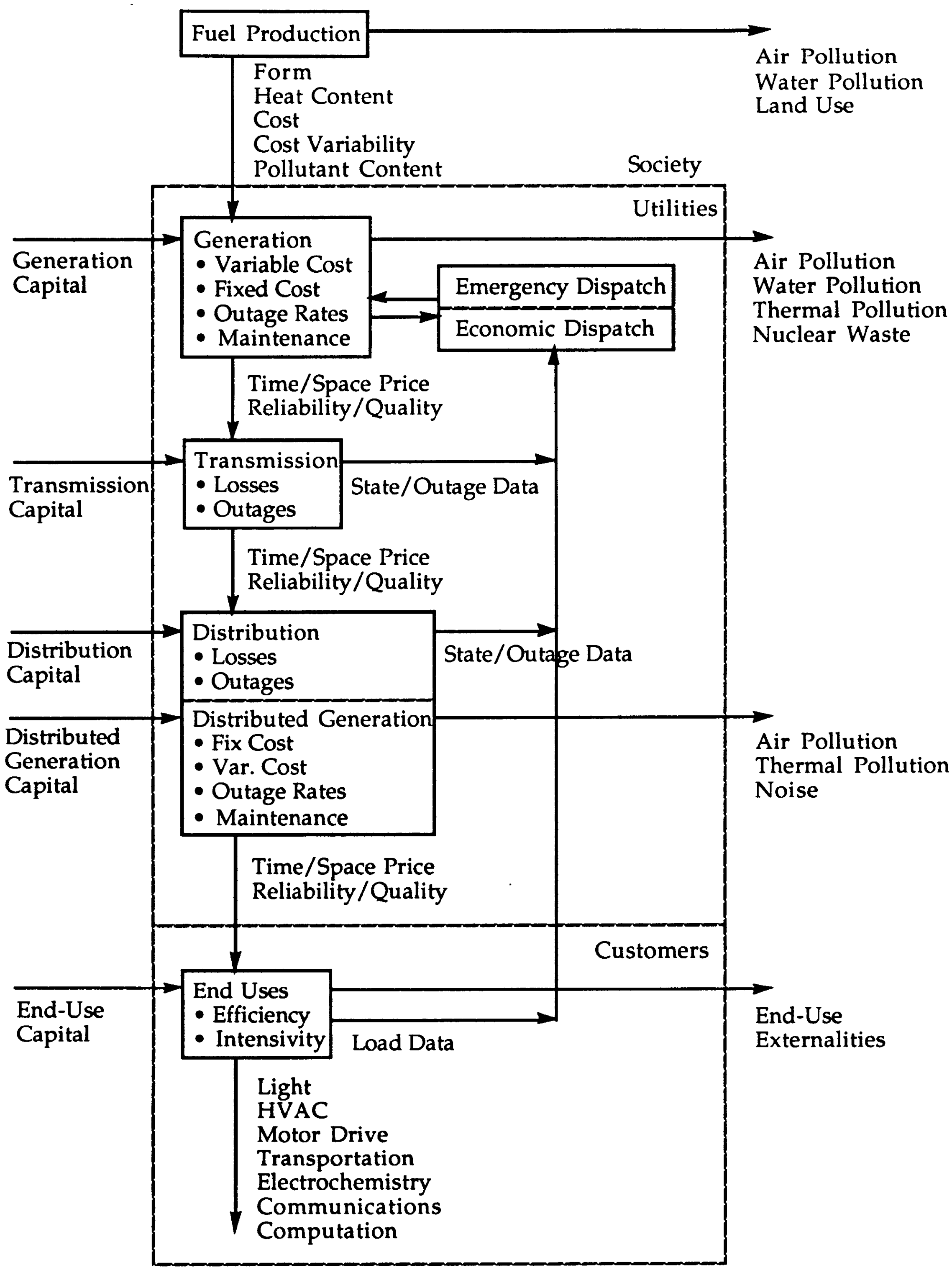
2.2 The Multi-Attribute Chain of Utility Functions

In order for full value estimation to be most valuable, it is important to be as comprehensive as possible in identifying individual options or component values which are available. There are two ways to attempt this. The first is to review the planning literature to see what range of options and values have previously been considered for use in the planning process. Where such references have been found, they are mentioned in Chapter 3 which discusses specific component values. The problem with this method is that it contains no systematic basis, and it is impossible to prove completeness (i.e. that prior work is definitive and can all be found).

The other method is to structure the search for individual options and component values through a conceptual framework. This thesis proposes that such a framework can be formed by combining the spectrum of time scales used for different planning purposes as shown in Figure 1.1 with the sequence of utility functions which are shown in Figure 2.1 below.

In this diagram, energy flows downward, from fuel purchases through generation, transmission, distribution and end use. Information flows related to the state of the system (load, outages, etc.) flow back up and are used for economic and security dispatch. Capital additions to the existing generation, transmission, distribution and end-use capital stocks enter from the left, while externalities from each sequential function exit to the right. Note that these functions are independent of ownership. The chain of functions may be split between more than one utility, by wheeling, or by complete vertical dis-integration of the generation, transmission, distribution and dispatch functions.

Figure 2.1 - The Chain of Utility Functions



By looking at each link in the chain of utility functions, considering the inputs and outputs of each step, and thinking about all the possible actions which can be taken over the short run to long run time frames, a comprehensive framework for identifying utility options is formed. The strategic utility planning process has traditionally focused on the long term end of the time scale, and upon the choice of individual capital additions in the form of specific generation technologies, transmission capacity or end-use technologies (DSM). However other options characterized by different time scales or different locations on the chain of utility functions deserve to compete with traditional options in the planning process. For example seasonal fuel switching, and non-economic dispatch (i.e. emissions adders) are options with medium and short term time scales that may compete directly with long term capital addition of emissions control technologies. Other dispatch options may reduce cost or risk or increase reliability. Rate structures (e.g. time of day pricing or interruptible rates) are options that can compete directly against DSM technologies. Maintenance, refueling, or life extension options may extend the use of current generation capacity, just as the addition of switchable capacitors or transformers may extend existing transmission capacity. Spatial and temporal heterogeneity also play a role, so that the siting and time of day operation should also be considered part of how an option is specified. The point is that range of options that can be combined into a balanced planning portfolio should not be limited, and these options should be considered and evaluated on the most fair and even basis possible.

The same conceptual framework that is used to identify utility options can also be used to identify sources of utility value, with some additional considerations. These include the number of market participants who perform the chain of utility functions, the multi-attribute nature of the inputs and outputs at each stage of the chain, and the spatial and temporal heterogeneity of the utility system.

Options can be identified and considered independently of whatever market participant would actually build or implement them. The question of value is more complex, because economic value depends on what the customer is willing to pay. In conventional planning there has only been the utility and the customer, with the dividing line at the electric meter. Because the price of electricity has been fixed by regulation, value has existed in any option that allows the utility to pay less for its inputs, or in any option that has provided more or better end-use services to the customer at the same price per kWh, including DSM or load management. When the utility is integrated, the value associated with each function may or may not be recognized. Even if such value is implicitly recognized, it may not be quantified as an internal price or used for planning purposes. However this relatively simple view of value is changing with the onset of deregulation and competition. The functions which have been combined into the vertically integrated utility need to be considered separately, based on the values of inputs, outputs and externalities at each stage. As the industry becomes segmented, it is even more important that these values become recognized and explicitly used for planning. In some cases this valuation may be an internal price for whatever organization is performing the function, and in others there may exist a competitive market which will generate a price.

The second consideration that makes finding values somewhat more complex is that at every step in the chain of utility functions the inputs and outputs have multiple attributes. Utility inputs are primarily capital goods and fuels, both of which have costs, but these inputs are also characterized by future price uncertainty, heat contents and efficiencies, pollutant contents and emissions rates, etc., all of which must be traded off against each other. Once electricity is generated, it too is characterized by several measures. Cost per kilowatt hour is the most important, but electricity is also characterized by capacity cost, VARs, power quality and reliability, which have different values for different customers. The value of electricity for customers also depends upon multiple attributes of the electricity input and the electrical services produced. Figure 2.1 lists some of the major electrical services, including lighting, HVAC, motor drive, electrochemistry, communications, and computation, and each of these provides a blend of cost, efficiency, safety, etc. compared to other sources. Finally, society as a whole bears the cost of multi-attribute externalities which are born neither by utilities nor customers. These include air and water pollution, land use, waste heat, and nuclear waste. As shown in Figure 2.1, these occur upstream of generation in fuel production (mining and drilling, refining and beneficiation, and transportation), as a product of generation, and downstream as byproducts of electricity use (although electricity is cleaner than competing fuels). Uncertainty could be mentioned as an additional attribute, but it really applies to all of the many attributes mentioned above, from price to forecast load to emissions impacts.

The third consideration with finding utility values is that state of the utility system is not homogeneous. Instead, the many attributes described above vary with both time and location, as indicated by the attribute labels at the different steps of the transmission and distribution chain shown in Figure 2.1. The variations in daily and seasonal load means that the marginal cost of generation is temporally inhomogeneous, that is it varies over time with changes in load. This has obviously been recognized since the earliest days of utility planning, but using this marginal cost as the basis for purchasing power from non-utility generators was first implemented in 1978 by the Public Utilities Regulatory Policy Act (PURPA). Presenting this value to the customer through the rate structure as the basis for load management is more recent, with the theoretical basis for time of day pricing first presented in 1981 by Schweppe, Tabors and Kirtley[7]. Time of day pricing is now common in wholesale power transactions, but retail time of day rates are still uncommon.

However the marginal system cost is not just time dependent. It is obvious that different generating plants have different costs, and that these plants are located at different points on the transmission network. Because power transmission and distribution depends upon the electrical laws of network flow, the geographic distribution of load on the network may mean that plant dispatch may vary from the economic optimum in order to maintain synchrony between generators. This means that increasing load at different network nodes may produce different marginal costs. Wheeling power across the system also affects nodal prices, and may both increase and/or decrease them depending upon the direction of the transaction. In addition to this short term spatial heterogeneity of marginal dispatch cost,

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[7] Schweppe, Fred C., Richard D. Tabors and James Kirtley, *Homeostatic Control: The Utility/Customer Marketplace for Electric Power*, MIT Energy Laboratory Report, MIT-EL 81-033, September 1981.

local transmission and distribution capacity constraints also imply heterogeneous long term T&D expansion costs.

Other attributes in addition to system marginal cost may also be temporally or spatially heterogeneous, including power quality and reliability and environmental externalities. Air pollution emissions are a good example of this, since health and environmental impacts depend upon urban v. rural origin, wind direction, and seasonally dependent atmospheric chemistry transformations.

The recognition of the heterogeneity of system attributes also leads to questions of equity. Obviously prices or emissions that are based on geographic location or time or day or season will favor some customers over others. As a regulated monopoly supplier with an obligation to serve all customers, utility rate structures have incorporated social policy through rate structures (e.g. average pricing) and obligation to serve. The question of how to deal fairly with customers who may lose essential service due to peak hour needs or remote location will need to be dealt with as part of deregulation.

2.3 Component Values and the Structure of Full Value Estimation

Traditional valuation has been based only on technological options, whether a single generator or DSM program. Even when additional sources of value like environmental externalities have been added into the planning process the emissions have been assumed to depend only on the technology and not on the future dispatch of the system in which the option is placed. The M.I.T. Energy Lab has been prominent in the use of multi-attribute studies that analyze option/system interactions, and utilities also use production cost models to study how technologies will be utilized, but the point is that this is not generally carried through to the regulatory process which approves utility supply plans.

On the other hand, component values tend to be based on the interaction between the option being evaluated and the rest of the utility system. They can be generally related to the following areas which are used to organize further discussion in Chapter 3.

- Dispatch
- Transmission and Distribution
- Reliability and Quality of Service
- Financial Risk
- Environmental Impacts

Dispatch values are based on the way that the system is operated, which can be based on the addition of a traditional generating technology or system security or environmental reasons. Transmission and distribution values are based on different ways that options can avoid investment in new T&D capital. Reliability and quality component values are based on how options may either provide better service to customers who need it, or less expensive but adequate service to customers who do not. Financial component values can be identified based on the number, size, diversity, risk and contractual terms of both capital and fuel purchases. Environmental values can be based on costs or savings in meeting emissions or other pollution standards. This classification is somewhat arbitrary, since a T&D option may claim both dispatch and reliability benefits, and the value of spinning reserve may be classified as either a dispatch or reliability component..

These component values can be separated from the options which may possess them. A single option (e.g. distributed natural gas fuel cells) may have several component values, including dispatchability, reduced transmission and distribution requirements, high reliability, and low environmental impacts. On the other hand, the economic benefit of reducing spinning reserve can be evaluated regardless of whether this is a dispatch option which reduces system reliability or a fast interruptible rate structure option which reduces necessary spinning reserve without reducing system reliability. Component values have been primarily claimed to date for individual, non-conventional technologies, e.g. the transmission benefits of distributed photovoltaic generation, but correct planning requires that they be identified and comprehensively applied for all options.

This thesis defines component values in monetary terms, so in general the dependence of component values on multiple attributes is based on the willingness to pay for each attribute. Electrical service is characterized not just by energy and capacity, but by VARs, security reserves, reliability and quality.

With unbundling of electrical services these different attributes will each have a market and a price based on supply and demand.

Environmental component values are different. There is still a utility supply curve relating costs to emissions, based on the most efficient strategies for reducing emissions. However, by definition there is no direct customer for externalities whose cost is born by society as a whole. Stakeholders in the policy making process do not in general agree on what these costs (e.g. for air emissions) may be. Markets for trading emissions allowances go part way towards setting a value on externalities, but only in the sense of efficiently allocating emissions caps and not in setting emissions levels where marginal societal cost equals marginal societal benefits. Therefore utility planning can at present only address the question of efficiency in reducing emissions and not the question of an optimum level.

Not all component values are equally simple to quantify, and this leads to the question of how component values can be classified. Figure 2.2 below shows the classification scheme used for discussion in this thesis.

Figure 2.2 - Classification of Component Values

	Quantifiable	Unquantifiable
Generic		
Specific		

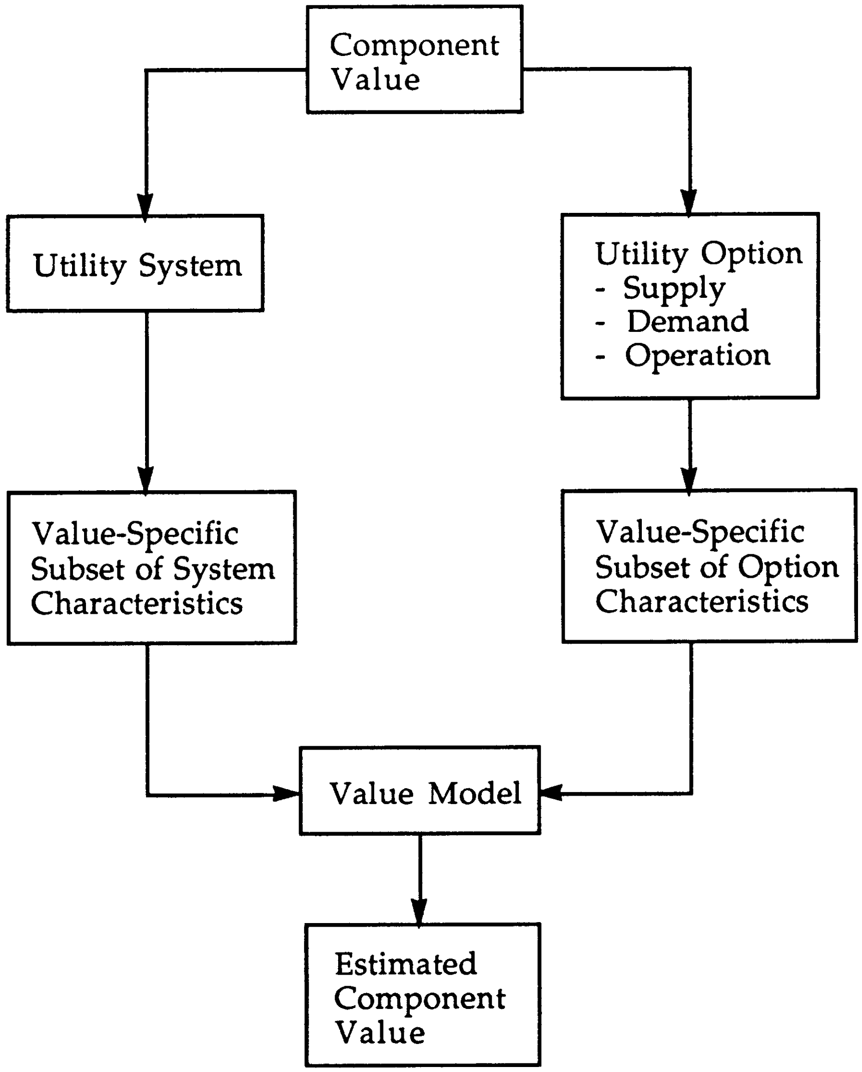
This classification is similar to the one used for fuel reserves, where one axis is based on information (known or unknown) and the other axis is based on availability (economically recoverable or unrecoverable). In this case, the information axis is based on whether the relevant utility system data is uniform or variable across space or time. If the information relevant to the component value in question is uniform or homogeneous then the value is generic for the entire system, whereas if it is heterogeneous the value is specific. Transmission and distribution component values are generally specific, since they depend not only upon the option but where it is placed in the system due to spatial heterogeneity of the T&D network. Dispatch component values are generic, and can be evaluated based only on option characteristics and/or generic system characteristics. On the availability axis a component value may be either quantifiable with current analytic models or methods, or unquantifiable where current methods are not identified, available, or agreed upon.

This classification means that generic, quantifiable component values will be the easiest to determine, but analyzing a specific, quantifiable value will still depend upon the available of the heterogeneous data. If a component values cannot be found due to the lack either of tools or data, it is still important to establish the relative scale of the component value as far as possible. This may make it possible to compare a qualitatively large but indefinite component value from one source to a smaller but quantifiable component value from another source. For example, some options will definitely have a long term transmission and distribution component value and we know simply from the amount of capital invested in T&D that this value could be large, but strategic models that combine generation and transmission expansion analysis do not currently exist.

2.4 Evaluation of Component Values

The structure which this thesis proposes to evaluate component values is shown below in Figure 2.3

Figure 2.3 - Structure for Evaluation of Component Values



As this figure shows, the analysis proceeds from the identification of a single component value. Option and system characteristics are defined as facts which describe the option or system and which are used to model the interaction between the two. The subsets of these option and system characteristics which are relevant to the evaluation of a particular component are identified, and an appropriate value model is used to quantify the monetary value of this component. This value model may be either a theoretical mathematical analysis or simulation model. Production cost models are the most common computer simulation models used for analyzing utility systems, and may be based on either hourly load dispatch or load duration curves.

This mapping from component value to subsets of option and system characteristics is important, because it means that a value can be quantified independent of any specific option technology or system. The options or system in question can vary in other ways, but as long as the relevant subsets of characteristics are the same the component value will remain unchanged. For example, the value of spinning reserve depends upon a subset of system characteristics. If a utility rate structure option increases prompt interruptible load and allows lower spinning reserve, or the spinning reserve level is simply changed as a dispatch option, the value will depend only on the system's marginal cost supply curve and unit dispatch constraints.

Table 2.1 and 2.2 below illustrate this mapping. Table 2.1 shows the subsets of characteristics which are relevant to the different general classes of component values which have been identified. Table 2.2 then shows the mapping between characteristics and three individual options which vary significantly. Some characteristics apply to all options (like cost), while others apply only to some kinds of options. A similar table mapping system characteristics to different options can also be constructed, but this is not very interesting because all systems have the same set of characteristics, although their quantitative values obviously vary significantly.

Table 2.1 - Utility Value to Characteristics Matrix

System Characteristics / **Values**	Average Cost	Dispatch	T&D	Reliability	Quality	Financial Risk	Environment
Plant Base (Number & Size)		√	√	√		√	
System Fuel Mix		√				√	√
Plant Efficiencies							√
System Marginal Cost Curve		√	√			√	√
Storage Fraction		√					√
Non-Dispatchable Fraction				√			
Load Distribution - Temporal		√	√	√	√		
Load Distribution - Spatial		√	√	√	√		
Network Topology & Limits		√	√	√	√		
Load Forecast & Uncertainty						√	
Fuel Prices & Uncertainty						√	
Financial Condition/Risk Level						√	
Rate Structure						√	
Emissions by Plant and Fuel							√
Option Characteristics							
Unit Size	√	√	√	√	√	√	√
Capital Cost	√					√	
Fuel Type & Cost	√					√	√
Heat Rate (Efficiency)	√						√
Dispatch Cost	√	√				√	√
Maintenance	√	√		√			
Forced Outage Rate	√	√		√			
Energy Storage/Efficiency	√	√	√	√			√
Load Shifting/Efficiency	√	√	√	√			√
Dispatch Constraints		√					
Dispatchable/Non-Dispatchable		√	√	√	√		
Central/Distributed			√	√	√		
Network Location			√	√	√		
Temporal Distribution		√	√	√	√		
Option Flexibility						√	
Fuel Flexibility						√	√
Emissions							√
Power Quality (e.g.VAR support)					√		

Table 2.2 - Utility Option to Characteristics Matrix

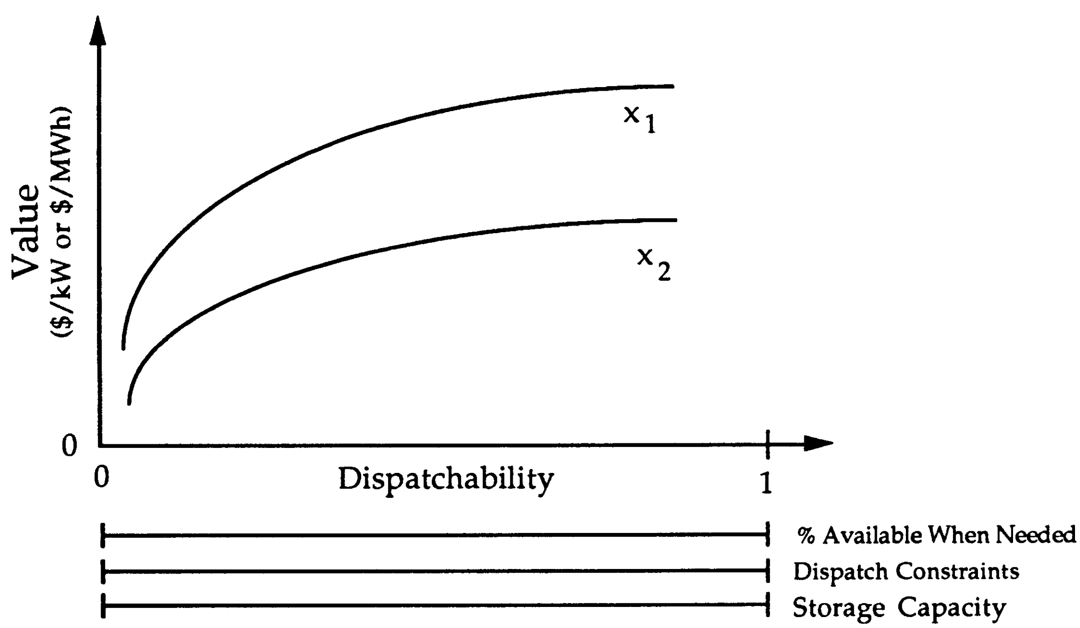
Option Characteristics	Utility Options: ALWR	Solar PV	DSM
Unit Size	√	√	√
Capital Cost	√	√	√
Fuel Type & Cost	√		
Heat Rate (Efficiency)	√		
Dispatch Cost	√		
Maintenance	√	√	
Forced Outage Rate	√	√	
Energy Storage/Efficiency			
Load Shifting/Efficiency			√
Dispatch Constraints	√		
Dispatchable/Non-Dispatchable	D	N	N
Central/Distributed	C	D	D
Network Location	√	√	√
Temporal Distribution		√	√
Option Flexibility		√	√
Fuel Flexibility			
Emissions			
Power Quality (e.g.VAR support)	√	√	

This method of analyzing a single component value by proceeding from value to the relevant option and system characteristics to an appropriate model to some quantitative value can be repeated, since a single option may have more than one component value which applies to it. By adding up all of these individual component values, a wide range of utility options can compete on an even basis.

2.5 Construction of Value Supply Curves

Section 2.3 above has described how to evaluate a single component value using a subset of option and system characteristics, independent of any single option technology. This thesis further extends this framework by varying parameter data for the subset of option and system characteristics, so that a value supply curve can be constructed. It is not interesting to vary most system characteristics for analysis, because in reality the inertia due to sheer system size makes them slow to change. However, some system parameters such as dispatch policies (e.g. for emissions control or spinning reserve) can be changed rapidly and these may be of interest. Figure 2.4 below shows a schematic value supply curve which illustrates how this may be done using the example of generating unit dispatchability. This graph shows the expected result that increasing generator dispatchability will increase overall value by decreasing total system dispatch cost, and this value shows decreasing returns as dispatchability is increased. The label on the horizontal axis will depend upon the parameter which is varied and the way in which dispatchability is defined. The figure below shows several alternate horizontal axes, including a generic label of percent availability when needed, and specific labels indicating real dispatch constraints for thermal units and storage capacity for otherwise non-dispatchable units such as solar PV or wind generators.

Figure 2.4 - Schematic Value Supply Curve



In some cases, it may be interesting to explore the component value's dependence on two or more option characteristics, and the component value supply curve can be extended to a value surface (in 3D) or a family of curves (in 2D). In the example of generating unit dispatchability, the value depends not only on the speed of dispatch, but also upon the dispatch cost of the generating unit in question. Figure 2.4 illustrates this by showing two curves for two different unit dispatch costs (x_1 and x_2).

The benefit of this approach is that the value of certain options can be determined independent of option technology. The supply curve for the value can be compared to the cost curve for the option that supplies it to find the optimum. In the example above, the two dispatch cost curves could reflect the value of dispatch response for a base load and an intermediate generating unit. Each of these units may be able to vary its response time by some amount for a certain cost, and by using the value supply curves above the optimum response time for a new base or intermediate load unit could be determined. By constructing supply curves for a range of component values, it should therefore be possible to screen the relative importance of certain option characteristics, and to design options or portfolios of options that combine the best levels of these component values to maximize the full value.

The schematic value supply curve shown above raises several issues. In the first place the option characteristics must be defined in a way that is capable of continuous variation. This may or may not be true for all options. For example, thermal line losses avoided by distributed generation are an obvious benefit, but these losses depend only on transmission line voltage and resistance, neither of which can readily be varied. The measure or scale of the variable characteristic may also be defined in several possible ways. For the example given above, the measure of dispatchability could be the unit's ramping rate, minimum run time or the minimum time between shutdown and the next start. The value shown on the vertical scale above will generally be in terms of total dollars for the period modeled, but for the purposes of comparison with other technologies it may be more useful to show it in terms of $/kW or $/MWh.

If the component value in question is generic, the value supply curve obtained will apply to any location in the utility system modeled, but a specific component value (e.g. deferral of T&D investment) can only be obtained for and apply to a specific location. Repeated modeling of specific component values for different locations is not theoretically difficult, but may depend upon how easy it is to gather the relevant data.

A more theoretical question is the issue of option/system independence which is assumed in this value supply curve approach. A component value can only be mapped against a variation in some option or system characteristic if the state of the fixed utility system is independent of the state of that variable parameter. This may hold for a snapshot in time, but fails at first examination over a long planning period (e.g. 20 years), when enough of a new option can be built to change overall system performance. This means that for strategic, long term planning the size of a component value may change with the system as it changes, so a single value supply curve is insufficient. However, it is possible to construct a family of curves based on both system and option characteristics, and read the value off successive curves as the system changes. If the state of the utility system is effectively independent of the option characteristics (e.g. for short time periods), then separate component values can also be considered independent of each other as long as the subset of option characteristics on which they are based are mutually exclusive.

In order to use component value supply curves to evaluate a specific utility option, the option is first analyzed to determine how many component values it may claim. If a value is generic, the option's characteristics can be used to directly read the component value from the supply curve for the system in question. If the component value is specific, the value of full supply curves can be calculated for that location. The component values (benefits or costs) for all the components identified are then added to the conventional value (or cost) to give the full value (or net cost). If the option's characteristics can be varied the supply curves can be used to maximize the full value.

Under current industry structure, these component values can be used by utilities as part of their integrated resource planning to compare internal utility options against those received from independent generators or DSM providers (often through a bidding process). Under industry deregulation, these component values can be used by whatever entity takes over the particular utility function which is the source of the component value. For example, transmission will presumably remain a regulated monopoly acting as a common carrier. By recognizing and incorporating component values into the transmission cost, generators and purchasers will receive the correct price signals. Distributed generators would reap the benefit of avoiding these charges. Likewise, whatever agency takes over the role of network coordinator for the purposes of system security may use component value information to pay for the correct level of spinning reserve or other security services.

Current changes in utility industry structure and regulation may be both good and bad in the context of calculating and incorporating component values. As mentioned above, some component values may be recognized and considered by utilities in their daily operation (e.g. dispatch constraints), but not explicitly included in current long range planning. Dis-integration of the industry will mean the loss of internal utility communications, and increase the need for such values to be more formally recognized and incorporated. On the other hand, utility deregulation provides the possibility of directly providing direct, bilateral market transaction prices for component values through unbundling of various services (e.g. spot pricing, reliability, and VAR support). Planning will likely benefit as free market players consider all factors that affect the bottom line, not just those contained in the present regulatory structure. However, it will be the states' responsibility to structure new markets and regulate the remaining monopolies to provide the correct price signals, including component values.

It is believed that the component value framework and supply curves described above will meet the deficiencies outlined at the end of Chapter 1 by; 1) showing how to find the complete range of utility options and values available, 2) incorporating option/system interactions, 3) separating component values from individual options and outlining how they can be classified and quantified, and 4) extending component values to supply curves that provide the parametric value of changes in option characteristics.

Chapter 3 next describes and discusses the range of specific component values identified, but the main thrust of this thesis in Chapters 4 and 5 is to demonstrate how to generate supply curves for a limited number of generic component values.

3.0 Review of Component Values Identified

This chapter reviews individual component values that have already been conceptually identified, and classified into the areas of dispatch, T&D, reliability, financial risk and environmental. This classification is summarized in Table 3.1 below, which also shows whether the component value is generic or specific, and whether it has been chosen for evaluation in Chapters 4 and 5. The discussion of individual components includes the following areas.

- What is the source of value.
- What option and system attributes are relevant to it.
- The current status of research or use.
- What models if any currently exist to evaluate it.
- How the component value may be used in traditional and competitive planning.

Several possible schemes for competitive deregulation exist. The power pool method where a central pool company purchases power from independent generators is not far removed from traditional planning, while the most extreme method of competition is to allow independent bilateral purchase and sales transactions. The discussion below presents how component values may be used under the two extremes of traditional planning and in a competitive bilateral transactions market.

Table 3.1 - Classification of Component Values

Component Values	Generic	Specific	Evaluated
Dispatch Components			
Load Curve Shape	√		
Load/Capacity Mismatch (Excess RM)	√		√
Thermal Dispatch Constraints	√		√
Non-Dispatchable Resources	√		√
Spinning Reserve	√		√
Non-Economic Dispatch	√		
Transmission & Distribution Components			
Line Loss	√		
Changes from Network Flow		√	
Reduction/Deferral of Capital T&D Costs		√	
Reliability & Quality Components			
Loss of Service		√	
Inadequate Service		√	
Financial Risk Components			
Excess Unit Capacity (Lumpiness)	√		√
Construction Flexibility	√		
Capital Cost Risks	√		
Fuel Cost Risks	√		
Supply/Demand Diversity	√		
Environmental Components			
Externality Supply Costs	√		

3.1 Dispatch Related Component Values

Options that affect or constrain utility system dispatch produce a change in the total production cost of the system. Such dispatch related values are some of the most obvious reasons why utility options must be evaluated by how they interact with an existing system, and not on an individual technology basis. The problem with this definition of course is that almost every utility option affects dispatch in some way. A system is by definition interrelated, so classification can be arbitrary. For example, options that affect dispatch due to network transmission constraints are considered as part of the T&D class of component values below, and the effects of excess option size are considered below under economic risks. For the purposes of this thesis, the category of dispatch related component values has been chosen to include values related to system load shape, the match between load and capacity, and individual unit dispatch constraints, all or which are generic and not linked to any specific network location.

Change in Load Shape

The importance of a flat load curve has been recognized since the very beginning of utility planning, as described in Appendix 1, and the impact of load shifting can be very large if the shift is significant. Current utility options that can produce load shifts include the following.

- DSM efficiency programs, depending upon the time correlation of the end-uses with system load.
- Load management, depending upon the amount of peak load shifted, and whether utilities have active control or not.
- Hydro, compressed air and battery storage.
- Non-dispatchable resources (wind or solar PV), which affect the net load curve remaining for thermal generation.
- Electric vehicle market penetration.
- Utility rate structures, including especially RTP pricing.

Some of these options are included under load forecasting in current utility planning so that they do not compete directly against supply side technologies. The option/system characteristics which are relevant to calculating this component value are;

System	Option
Hourly load curve	Amount of load reduced or shifted
Supply cost Curve	Correlation with system load

This value is well recognized, if not explicitly incorporated in all utility planning. Conventional production cost modeling can be used to model the effects of changes in load shape. The chief impact which deregulation wil have for this value is to decentralize its consideration in planning. Under a competitive market of bilateral transactions, prices based on marginal cost will let customers choose whether supply or demand side options are more attractive, and suppliers choose whether to sell generation or DSM services.

Match of Generation Capacity to Load

Given the net load shape to be met by dispatchable generation, the system capacity needs to have both sufficient total capacity, and the correct blend of base, intermediate and peaking load generating units. A mismatch of load and capacity is given solely by a subset of system characteristics..

System	Option
Hourly load curve	
Supply cost curve	

Excess capacity can occur due to incorrect load forecasts, and effectively shifts the normal capacity balance because excess capacity effectively shifts up the dispatch order and is used to meet intermediate or peak loads. The savings in fuel costs and emissions due to base load dispatch of newer, more efficient plants may or may not justify the high reserve margin. The value (or cost) of either excess capacity or a system whose plants' capital to fuel cost balance is mismatched to load is well recognized by conventional analysis, but since this problem arises out of prior planning decisions whose costs are already sunk it has not played a large role in planning. Normally there is no 'cure' for a high reserve margin, except to wait for load growth to catch up (or claim that it is necessary for reliability). With the advent of competition however, recovery of sunk costs is not guaranteed and non-competitive individual generating plants will presumably be sold at their new and lower market value or be retired. Normal production costing models can be used to determine the cost of excess reserve margin, and this is presented in Chapters 4 and 5.

Dispatch of Generation Capacity

System dispatch can also be affected by constraints on the operation of individual plants. These constraints can be based on the physical limits of the generation technology or energy resource, or upon non-economic dispatch constraints or rules.

- Thermal Generation Dispatch Constraints - Due the economics of matching generation to the load curve, base load units are large, efficient, and have slower response times than peaking units which are smaller with higher dispatch cost and faster response times. This value can be evaluated solely from the existing system, and then applied to new options based on the following characteristics.

System	Option
Hourly load data	Dispatch constraint
Supply cost curve	Variable cost
Unit dispatch constraints	

Unit dispatch constraints may mean that a unit is kept in (or out) of the optimal, unconstrained dispatch order because expected short term load shifts mean that it will (or won't) be needed again soon. Dispatch constraints and reduced thermal efficiency during startup impose costs that are not captured in the production cost modeling usually used for strategic planning, which is based on load duration curves that ignore sequential hour-by-hour load changes. This component value may be calculated by using an hourly production cost model, but because of time and cost these models are usually used for tactical rather than strategic planning. Reduced dispatch constraints can incur higher maintenance costs and unit startups can incur increased emissions, so this value can be used under current market structure to determine the cost tradeoff of different maintenance and emissions levels. Under deregulation, this value can used to set a price on unit response times, including the value of advance notification time for interruptible load customers, which would affect the rates they pay. This method may also be used to evaluate the value of power purchases from other utilities or IPPs, based on contractual terms or constraints that may affect dispatch. The component value is analyzed and discussed in Chapters 4 and 5.

- Non-Dispatchable Resources. - Some energy resources are not dispatchable, including run of river hydro, wind, solar, and some cogenerators. Although most of these resources have low or zero variable dispatch cost, their value is still diminished by their non-dispatchability because the resource availability is not correlated to the daily or seasonal load curve. In order to analyze what dispatchability is worth, it is possible to add it by means of storage capacity. For run of river hydro this is done by building a dam, but this can also be done for the other resources above by means of batteries or other storage. To analyze the value of dispatchability, the following characteristics are relevant.

System	Option
Hourly load data	Hourly resource data
Supply cost curve	Variable cost
	Storage capacity
	Inverter capacity

The value of the correlation between generation and marginal system cost is recognized in utility planning, but the value of increasing dispatchability by adding storage and the optimization of storage and inverter capacity is not. This thesis finds the value due to the optimized use of storage as an example which is presented in Chapters 4 and 5.

For reasons of system security, there is also expected to be a practical limit to the total fraction of non-dispatchable generation in a system, and there would be a cost associated with this as the limit is approached. However it is estimated by Dr. Richard Tabors that the marginal economic value of non-dispatchable resources will probably by zero before security related limits are reached, and this cost has not been included in the non-dispatchable component value.

- Spinning Reserve - Spinning reserve consists of generating units in operation below their full capacity and is necessary to provide power on short notice when a generator or transmission line in service experiences a forced outage. As system load increases, spinning reserve units are dispatched at their full capacity and new units are selected for spinning reserve. This process is reversed as system load decreases. North American Electric Reliability Council recommended levels for spinning reserve are generally given in MW, but because the amount needed is related to the size of a possible outage, spinning reserve is also given by some standards as a fraction of the capacity of the single or two largest generating unit(s) in service at any time.

Several options can reduce the need for spinning reserve. Fast interruptible customers can shed load, or new instrumentation and control options may allow utilities to operate closer to their safety margin (substituting knowledge for error factors). Utilities may also simply make a cost tradeoff of how much reliability they wish to purchase by the spinning reserve level they set. In any case, the value of the spinning reserve is of interest for planning. This component value supply curve depends upon the following system characteristics and is independent of option characteristics, unless the new option becomes the new largest unit in service.

System	Option
Hourly load data	
Supply cost curve	
Capacity of largest unit	
Spinning Reserve Level	

The component value can be positive or negative, depending upon whether the option under consideration reduces or increases the spinning reserve level. Spinning reserve can be calculated by production cost modeling, and although some load duration curve models allow changes in spinning reserve level it will be more accurately calculated by an hourly model that can also include dispatch constraints. Under traditional utility planning the value of spinning reserve can be used by the utility to evaluate their cost v. reliability tradeoff, or to evaluate the increase required or decrease allowed by some planning option. Under a system of competitive bilateral transactions, spinning reserve is an ancillary service required for system security. The system operator may require buyers to pay for some amount of spinning reserve along with their power purchase, or the cost of spinning reserve may be added to the cost of transmission. In either case, options which reduce the need for spinning reserve would decrease the transaction cost. The value of spinning reserve is calculated and discussed in Chapters 4 and 5.

- Non-Economic Dispatch. - Fuel or emissions constraints or energy limited generation can cause changes from unconstrained economic dispatch. Such dispatch rules or constraints can include fuel switching, emissions caps or bubbles, emissions trading, seasonal emissions constrained dispatch, or emissions based cost adders. Under the framework of this thesis, these methods are utility options that compete against technologically based methods of reducing emissions, such as DSM, clean generators, or pollution control technologies. Dispatch options may be more cost effective, but must be properly evaluated for comparison with other, unconstraining options. When additional generation capacity is needed, then dispatch rule options can be analyzed with other options to find a portfolio that has the lowest overall cost. A production cost model that can handle these types of dispatch rules or constraints is normally used to see the systems effects on costs and emissions, but since a full porfolio analysis is not normally done when new capacity is needed such a model is not usually used. The option and system characteristics required for this type of model include the following.

System	Option
Hourly load curve	Dispatch rule
Supply cost curve	
Unit fuels and emissions	

Emissions taxes may also be evaluated under this component value, since they affect dispatch in the same way as emissions adders. However since emissions taxes are actually collected, the dispatch is not constrained but rather optimized to a new objective function. Indeed, if a dispatch constraint option is the most efficient way of achieving emissions reductions (or some other goal), then the changed dispatch will not be constrained, but rather most economical under the imposed regulation. Under deregulation, emissions or emissions permits must have a real price since there will be no other means of enforcing non-economic behavior.

3.2 Transmission and Distribution Component Values

Transmission and distribution component values can be important, because T&D costs are significant in two ways. First, the capital investment in T&D is large; approximately 40% of total utility investment as discussed in Section 4.1 and shown in Table 4.2. Second, line losses due to thermal resistance represent a large cost (approximately 10% of total generation overall). These losses can be minimized by higher transmission voltages or lower line resistance, but they can only be eliminated by distributed generation or increased end-use efficiency.

Utility T&D planning has been largely secondary to generation planning, focusing on expansion to meet growing generation and load under a range of outage scenarios. This planning covers a wide range of time domains, each of which can contribute to value, from long term planning (years) to operation and maintenance (months), dispatch(hours), and security (minutes and seconds). The longest term T&D planning has been at the boundary between strategic planning and operation, focusing on specific projects like generator location and line construction or upgrades. T&D planning tools to date have been concentrated on the constraints of network flow and a range of security limits (including thermal limits, voltage support, phase angle, and system synchronization) all under assumed outage scenarios.

Utility deregulation and increased wholesale power purchases wheeled across the T&D network are producing new models for improved transmission pricing[8]. Transmission networks are built to accommodate economic dispatch, based on generator location, daily and seasonal patterns of load distribution, and network flow. Imposition of large wheeling transactions across a transmission network can force a departure from strict economic dispatch in order to maintain generator synchronization and system security. Such models can produce the marginal cost of electricity at individual transmission network nodes, based on unit location, security constrained dispatch, and line losses. The value of transmission between two network points is then simply the difference in their marginal costs. The difficulty in expanding these models for long range, strategic planning lies in predicting the size and location of new generators, transmission lines, and load demand. Current production cost models used for generation expansion and strategic planning assume that the network is a single node, with all generation and loads at a single point. Thus, a comprehensive model for integrated planning has yet to be developed.

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8 Ilic, M.D., J. R. Lacalle-Melero, F. Nishimura, W. Schenler, D. Shirmohammadi, A. Crough, and A. Catelli, "Short-term Economic Energy Management in a Competitive Utility Environment", *IEEE Transactions on Power Systems*, Vol.8, No.1, pp. 198-206.

Given this perspective on T&D planning, there seem to exist at least four different sources of component value, including 1) line losses, 2) departures from economic dispatch, 3) departures from network flow, and 4) deferral of maintenance, replacement or new construction of T&D capital equipment. T&D component values are specific to their network location, and some are difficult to calculate. The most complete consideration of T&D component values by a utility to date appears to have been performed by Pacific Gas & Electric on their Kerman substation located in the San Fernando Valley[9].

<u>Line Losses</u>
<u>Departures from Economic Dispatch</u>.

These two sources of value have been outlined above. At the crudest level, line losses can be evaluated based on average system losses. In this case, line losses could be considered a generic component value, and DSM and distributed generation options could claim it. Line losses depend upon voltage and line resistance, so there is little way to vary line losses to construct a value supply curve.

At a more sophisticated and correct level of analysis, these two sources of value are calculated by the models which produce heterogeneous network marginal costs. Although the two values are conceptually distinct, the results do not separate them. In this case, they can be considered together as a specific component values which depend upon the network location of the option in question. The size of the option (e.g. generator or DSM capacity) can then be varied to see how the combined component values change.

Under a traditional utility structure the network marginal cost model can be used by utility planners to help locate generators and transmission line upgrades, and a component credit could be added to the bidding process for DSM and distributed generation options. Under competition, the network marginal costs will form the basis for economically correct transmission

[9] Shugar, Daniel S., "Photovoltaics in the Distribution System: The Evaluation of System and Distributed Benefits", *Twenty First IEEEE Photovoltaic Specialists Conference*, Kissimmee, Florida, May, 1990.

pricing by the transmission company, subject to regulation. This transmission price information would form the basis for new generators to make location decisions and customers to make purchase decisions, although some social equity concerns may arise of prices vary too much geographically. Marginal network prices are based on the the existing system and loads. For long term, strategic planning it is possible to either extrapolate current prices or forecast system additions and load growth, but neither approach appears very reliable.

Departure from Network Flow.

Transmission options such as switchable capacitors, inductors, transformers or high power solid state devices which can affect network flow by actively altering the transmission system configuration are becoming increasingly available. The first use of these devices will be to alter network flow and relieve the most highly stressed network sections. At the most extreme example, these changes could alter the transmission network from network flow to a switched network that could be actively controlled. These options provide value by enabling the existing network to carry power more efficiently, since their cost would be less than increasing transmission line capacities. This component value is specific to network location, and the same type of marginal network cost model can be employed to calculate their value.as long as the voltage, phase, and impedance alterations which these options provide can be handled. Option size can then be varied to construct component value supply curves.

Under traditional utility structure, these options can reduce costs and avoid the siting opposition that is associated with more traditional transmission network expansion projects. In a competitive environment, the transmission company will remain a regulated monopoly, and regulators will need to provide incentives for T&D options that will minimize overall costs.

Reduction and Deferral of T&D Costs

Load growth requires the existing T&D network to work closer to its operational limits. This stresses components like transformers, increasing maintenance and shortening service life. Further load growth requires the construction of new T&D capacity. In either case there is a significant cost for maintenance, replacement or new construction of capital investment. Distributed generation and DSM can reduce or defer this investment, creating a component value credit which can make DSM and distributed generation more attractive. The benefits of distributed generation may be reduced if it is non-dispatchable (as with many renewables), since T&D capacity for load backup may be required at times when load and generation do not coincide. Appropriate siting of new generation, transmission, or loads may also reduce stress on the T&D network and allow reduced T&D costs. This component value is well recognized, and has been the subject of both publications and conferences[10]

This component value is site specific, and depends upon the loading and physical condition of specific transmission lines, substations, and distribution lines. The value supply curve depends on how long an option can defer new or replacement T&D capacity, and so depends upon the set of options and system characteristics shown below.

System	Option
Local hourly loads	Capacity
Local T&D limits	Correlation with local hourly loads
Local equipment condition	

In remote locations the cost of a distribution power line is high enough that wind and photovoltaic power with storage are already economic. This component value can also help to make DSM and distributed cogeneration, photovoltaics, and fuel cells competitive in specific niche locations where the distribution system for existing utility service is stressed.

This component value can be used by traditional utilities as a credit to make qualifying options compete more fairly in their internal planning or in open bidding. Under deregulated competition, companies offering

[10] Lamarre, Leslie, "The Vision of Distributed Generation", *EPRI Journal*, April/May 1993.

distributed generation or DSM services will claim this credit by avoiding transmission (and possibly distribution) costs. Depending upon how these remaining T&D monopolies are regulated, new and replacement capacity costs may be evenly or locally applied. Local costing will enhance this component value for stressed or constrained network locations, but regulatory pressures for social equity may prevent this.

3.3 Reliability and Quality Component Values

The reliability of a generator in supplying power has value, but this section focuses on the component value of the reliability and quality of electrical service supplied to the customer. Reliability and quality are not strictly independent attributes of electrical power service, but they can be considered as orthogonal measures of this service. Perfect quality will include the correct sinusoidal waveform, voltage level, frequency, and reactive power, while perfect reliability wil mean the lack of any interruptions. .

Reliability and quality are heterogeneous over time and location on the T&D network. Outages due to major generation and transmission failures can cause rolling blackouts that affect large areas simultaneously, but most outages are due to distribution failures that depend on weather and surface power lines or transformer failures. Quality varies due to power factor due to line and equipment inductance and due to waveform contamination by lightning strikes and large customers.

Reliability and quality both have value to customers that depends upon the customers' needs. For reliability, this value depends upon the time and duration of an outage, the amount of prior warning which may be given, and the end-use service to the customers. The value can be especially high for some manufacturing processes (such as glass making, heat treating, tempering, baking, etc.). Hospitals require backup generators, so the value of utility reliability to them is low, but for home dialysis the value can be very high indeed. Studies have been done of how value depends upon customer class and outage characteristics[11]. Customer demand for reliability also depends the customer's end use. Most early services provided by electricity, including heat, light and motor drive, were relatively insensitive to waveform, but the increased dependence on electronics has placed an increased emphasis on this attribute.

This discussion of value in effect means that the customers needs define a demand cost curve, and that different customers may be willing to buy (and sell) different levels of reliability and quality service. The utility supply cost curve is based on many alternate means of providing these services, and the most economical means may not always be through major generation or transmission improvements. For reliability, the cost of backup generation or battery storage can be the backstop price, and other methods must be more cost effective. For reliability, power filters and capacitors to improve the power factor can also be more effective than systemwide improvements. The point here is that reliability and quality are services that can be unbundled from plain energy service and supplied at different levels to different customers under deregulation, and many ways of supplying these services can be purchased by either the utility or the customer.

From this discussion it can be seen that the value of reliability and quality depend upon time and location, and so constitute specific rather than generic component values. Supply curves for these values will depend upon the most efficient combination of all the different technologies which can supply them. Distributed cogeneration and fuel cell generation may deserve a component value credit for reliability or quality, while photovoltaic or wind generation without storage may incur a debit. For these reasons it is difficult to find a model to generate such reliability and quality component value supply curves.

Generators may supply some services related to bulk reliability, including energy, spinning reserve, VAR supply and system stability services related to automatic generation control (AGC) and voltage control. It has been estimated that approximately 75% or more of the value of generation is

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[11] Sangvhi, A.P., "Cost-Benefit Analysis of Power System Reliability: Determination of Interruption Costs", *EPRI Report EL-6791*, Project 2878-1, Palo Alto, CA, 1990.

due to plain energy (bulk kWh), while slightly more than 20% is due to reserve power service, and less than 5% due to system AGC, stability and voltage control[12]. Spinning reserve has been discussed above as a separate component value under the dispatch category. Reactive power (VARs) can be supplied by generators over a certain range determined by the VAR supply curve at only a slight cost, so this value is not high.

Under current industry structure, the emphasis has been on the reliability of bulk supply, and quality has been more of a customer service issue related to power factor correction and filtering. Reliability and quality services have been implicitly valued as part of the utilities obligation to serve, but not systematically considered or disaggregated for different customers.

Under a competitive market regime, the possible unbundling of reliability and quality from bulk energy service will mean that the supply of these services can be matched to customer needs according to the supply and demand cost curves. Regulators may need to still impose some minimum service standards for remote network locations that could not otherwise afford adequate service. Reliability and quality services supplied by generators (like spinning reserve) may be charged directly to customers or included in transmission costs by whatever agency acts as a network coordinator. Customers may wish to purchase equipment to supply their own reliability and quality needs, or these may be offered along with DSM services by the utility. Large customers may also sell some of these services (like interruptible service, VARs, and voltage filtering) back to the utility.

3.4 Financial Risk Component Values

Financial risk is an inherent aspect of utility operations, although it has been somewhat mitigated by the regulated rate of return due to monopoly status. The chain of utility functions shown in Figure 2.1 illustrates the chief sources of risk by the arrows that enter and leave the utility boundary. The input risks are related to the purchase of capital investments and fuel, while the output risks are related to forecasting customer load, the cost effectiveness

[12] Ongoing conversations with Dr. Richard Tabors.

of DSM, and possible changes in the costs imposed by externalities (e.g. through decreased emissions caps or tradeable emissions permits). Markets for trading wholesale electricity, electricity futures and emissions permits have been recently established that permit utilities to reconcile their expectations about the future, including future risks.

While utilities recognize risk, the normal utility planning process has focused on sufficient generation to meet an approved forecast, and on the cost per kWh generated or saved by specific technologies. The benefits of diversification and flexibility in planning strategies that will perform robustly over a range of possible futures deserve to be better quantified and included in the utility planning process. This thesis subdivides financial risks into the categories of capital risks and fuel risks, because risks in load forecasting are really risks in matching capacity to forecast load, and risks due to changed emissions regulations are met by capital and fuel choices. This section focuses more on capital risks because the specific component value associated with generator size relative to system size is further explored in Chapters 4 and 5. Fuel price clauses which exist in 38 states[13] have also partially insulated utilities (if not the public) from sudden changes in fuel prices.

Capital Cost Risk.

Large, capital intensive options may be risky, either because of uncertain costs (e.g. nuclear plants), or because of uncertain reliability or efficiency (e.g. DSM programs). These capital costs risks are usually balanced against fuel cost risks, due to the fuel to capital cost balance which shifts across the range from base load to peak load generators. Capital cost risks can be minimized by the choice of technology, unit size, the terms of purchase (such as turnkey contracts), and obtaining prior regulatory approval (e.g. advanced siting or standardized reactor designs). One of the larger and easier to analyze component values is associated with unit size.

[13] National Association of Regulatory Utility Commissioners, *Utility Regulatory Policy in the United States and Canada, Compilation 1993-1994*, Table 176.

- Excess or lump capacity - Electric utilities have had a historic trend towards ever larger generating plants, driven by load growth and economies of scale and culminating in the construction of the current generation of nuclear power plants. This trend has reversed in the recent past as generators based on natural gas-fired aero-derivative combustion turbines and the growth of non-utility generators have combined to drive down the average size of new units. Economies of scale in size have been replaced by economies of scale in number as major components have become more standardized.

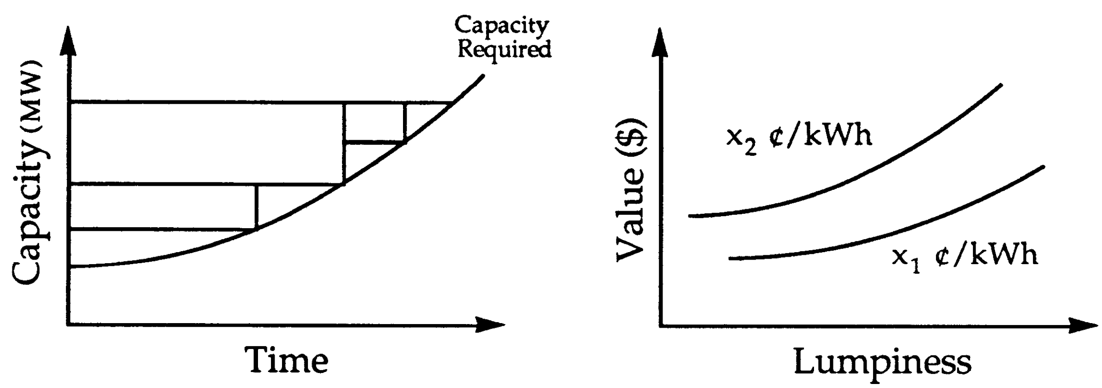
Generators which are large relative to utility system size have had historic problems with the consequences of cost overruns, including rate shock and prudency hearings. This has led many utilities to joint ownership of large nuclear units, so that their large capacity is spread over a larger total system size. Large generators also require longer construction periods, which lead to risk from changes in fuel markets and load growth. The advantages of small unit size relative to system load growth are also seen in some utility options like wind power or DSM. These are generally evaluated at some aggregate level (e.g. a wind farm with many individual turbines, or a DSM program with many different types and locations of efficiency improvements), but the diversity of many small units reduces the maximum size of probable outages and simplifies maintenance requirements.

Building a new generating option that is too large means that capacity increases in a large step function and most of this 'lump' of excess capacity is not required until system load growth grows enough to need the capacity. Because large plants are generally baseload and new plants are more efficient, this excess capacity is used, and the 'excess' shifts up the dispatch order to less efficient baseload and mid-load plants. The savings in fuel costs and emissions may or may not justify the large size of the plant.. The balance between these factors may give an advantage to smaller plants built sequentially, especially with decreases in economies of scale for large plants and increased availability of modular generation units. Thus there appears to be a component value associated with smaller unit size relative to the system. This value may be captured by conventional production cost modeling, but will be ignored if a utility compares individual technologies without considering how they interact with the existing system. The key subset of characteristics that matter for this component value are as follows.

System	Option
Load growth (MW/yr.)	Size (MW)
Supply cost curve	Variable cost
Load demand curve	

Since there are only two technology characteristics that are of major importance, it is clear that a graph can be constructed comparing size against cost, and a family of curves for different variable costs can also be constructed, as shown below. In the example shown in Figure 3.1 below, the 'lumpiness' scale is geometric, and the graph of capacity additions show three possible trajectories as a single large generator is replaced first by two units of one half the size, and then by four units one quarter as large. Although this value will depend slightly upon variable dispatch cost, it is clear that the most value is available at low dispatch costs, because base load plants are the largest.

Figure 3.1 - Schematic Value of Unit Size



Although this component value is conceptually similar to the value of reserve margin considered under dispatch components above, it has been separated for two reasons. First, the value associated with overall reserve margin can be given to options which reduce the total amount of reserve margin the system needs for maintenance and reliability. The value of 'lumpiness' is concerned with the short term jump in reserve margin above normal levels which can be produced by a single large unit.

This component value which measures the value of unit size represents a lower limit, and additional component values for smaller plants can be based on flexibility in planning. In the simplest case this means that if load growth should change in the example above, construction of later units could simply by halted. In a more sophisticated example, a gas combustion turbine unit could be expanded into a combined cycle unit, and then have a coal gasifier added. The flexibility to make decisions in stages over time as more information becomes available produces more value than if the final plant were built from the beginning. Decision analysis models for this type of decision making are well known, and extend to other situations, including fuel switching and construction of options portfolios. The value of flexibility is discussed further in Section 5.2.

Fuel Cost Risk

The risks associated with future fuel costs can be observed by looking at the comparative historical variability in prices for different utility fuels. These risks may be minimized in a number of ways, including; 1) long term fuel contracts, 2) fuel switching in the event of future price shifts, 3) fuel diversity to reduce dependence on a single fuel, and 4) the choice of technologies with low fuel price risks (e.g. DSM, nuclear, or renewables). Options 2, 3, and 4 also minimize the risk from increased emissions constraints. These four options also apply to non-utility generators, who may either bear the fuel cost risks themselves or pass them on to their customers through contracts which are indexed to fuel prices.

Although utilities need to consider competing strategic planning options based on consistent fuel price forecasts, the emphasis is on using the best forecast available and not on the fact that any single forecast is bound to be wrong. Clearly, a risk related component value would be useful to reward options with low fuel risks and penalize options with high fuel risks.

The impact of utility strategies on both capital and fuel risks can be evaluated by a number of techniques, including the following.

- Financial options and portfolio evaluation techniques.
- Risk-adjusted discount rates for uncertain cost streams (e.g. fuel prices)[14].
- Decision tree analysis for flexible options.
- Insurance premia

From a societal point of view a diverse and flexible power system is an advantage, and a power supply market that considers its own risks appropriately should incorporate these benefits. Under traditional electric utility planning, capital cost risks are born primarily by utility shareholders and to a lesser extent by utility bondholders, and fuel cost risks are shared with customers. Risk based component values could be used by the utilities to choose options that reduce these risks.

Financial risk appears to be the class of component values which a competitive market will most readily incorporate with out imposing any market structure or signals, because these types of risks are part of the normal course of any business. Under competition, generation capital cost risks are born by the generation company. The way in which fuel risk is shared between generator and customer depends upon the terms of their contract. The generator may pass its risks on to the customer, or if the contract insulates the customer from risk by a fixed price or a limit on price increases, then the generator may choose to diversify or insure against its own risks by a blend of fuels and long term fuel purchase contracts. The customer in turn may choose to trade low price for the risk of future price increases, or he may pay a price premium for decreased risk.

3.5 Environmental Component Values

The electric utility sector produces a wide array of environmental externalities, both directly and indirectly. Air pollutants (including SO_2, NO_x, CO_2 and particulates) are the emissions of predominant concern, but other externalities include radioactive waste, thermal pollution, flyash, mine

[14] Awerbuch, Shimon, *Risk-Adjusted IRP Procedures: Reflecting the True Costs of Conventional and Solar Options*, draft report submitted to National Renewable Energy Laboratory, Golden, CO, July 1992.

leachant, and noise. The utility planning process has focused on direct power plant emissions, but numerous studies have been done which calculate fuel cycle and life cycle impacts for different fuels and generation technologies. These many different types of pollutants produce a wide array of impacts, which range from direct and local to diffuse and global.

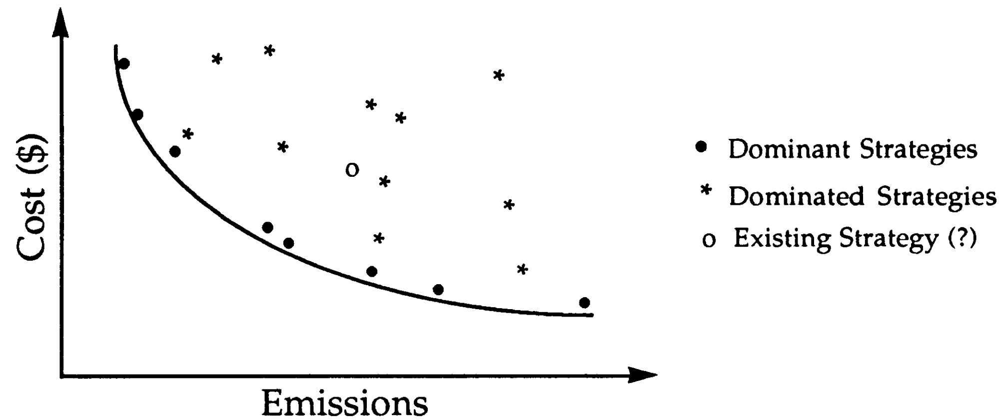
In order to reduce externalities, utilities have implemented a wide range of measures, including control technologies, emissions caps or limits for plants, utilities or regions, trading of emissions permits, emissions adders for non-economic dispatch, and the inclusion of emissions adders in the bidding process for new generation. Production costing models have been adapted and developed to track emissions and handle the many different forms of dispatch constraints and optimization involved.

Classical economics argues that environmental externalities should be internalized (i.e. through emissions taxes) until the marginal benefit of pollution (tax income) is equal to the marginal cost of environmental damage and morbidity. However the difficulties involved in modeling air transport, atmospheric chemistry, and damage and morbidity impacts are significant, and transforming damage and morbidity into dollars involves ethical considerations that make it difficult to reach consensus. For these reasons utility environmental planning has addressed primarily the issues of efficiency and allocation in reducing emissions, rather than finding the optimum level of pollution. In economic terms the supply cost curve for individual pollutants can be found, but not the 'demand' or damages cost curve. For these reasons, pollutant limits have been determined politically.

The problems with current utility planning and regulation are several. First, when the choice of new generation includes environmental adders in the selection or bidding process, the size of the adders may be questionable (e.g. damage costs) or economically irrational (e.g. emissions control technology costs). Second, the total cost of environmental adders is usually based on an assumed capacity factor, instead of how the plant will actually be dispatched based on interaction with the existing utility system.

Prior planning work by the M.I.T. Energy Lab has evolved a multi-attribute, multi-scenario approach that presents the results of many strategies over many different possible futures[15]. The cost v. emissions results for each pollutant contain a dominant set of options which form a tradeoff curve or frontier, as shown below in 3.2.

Figure 3.2 - Dominant Set of Least Cost Pollution Strategies



At least one member of the dominant set of options is always both cleaner and cheaper than any member of the dominated set. For this reason the tradeoff frontier represents a cost supply curve for a single pollutant, which shows the total system cost and marginal cost for different pollution levels. This curve is directly analogous to the component value supply curves discussed in this thesis. The major problem is that the dominant set for different emissions does not necessarily contain all the same options or have them in the same order. This means that a compromise option is sought that is at least close to the tradeoff frontier for each pollutant.

This multi-attribute, multi-scenario approach can be applied to traditional utility planning in order to find the most cost effective option for meeting predetermined emissions limits. The production cost modeling involved is based on the following set of characteristics.

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[15] Connors, Stephen R., "Informing Decision Makers and Identifying Niche Opportunities for Windpower. Use of Multiattribute Trade-Off Analysis to Evaluate Non-dispatchable Resources.", *Energy Policy*, Volume 24, Number 2, pp. 165, 1996.

System	Option
Hourly load curve	Unit Size
Supply cost curve	Variable cost
Unit emissions	Emissions rates
	Hourly availability
	Dispatch rule (if any)

Under a competitive market with bilateral transactions, emissions controls must be based on real price signals. The government can limit emissions by setting the total amount of tradeable emissions permits (in which case the initial allocation may be an issue), or by imposing emissions taxes on generators. In either case, these costs would be passed to customers and the market would act to limit sales (and emissions) by these generators. If revenue neutrality was desired it would be possible to rebate the emissions taxes to customers, perhaps through reduced transmission or distribution costs.

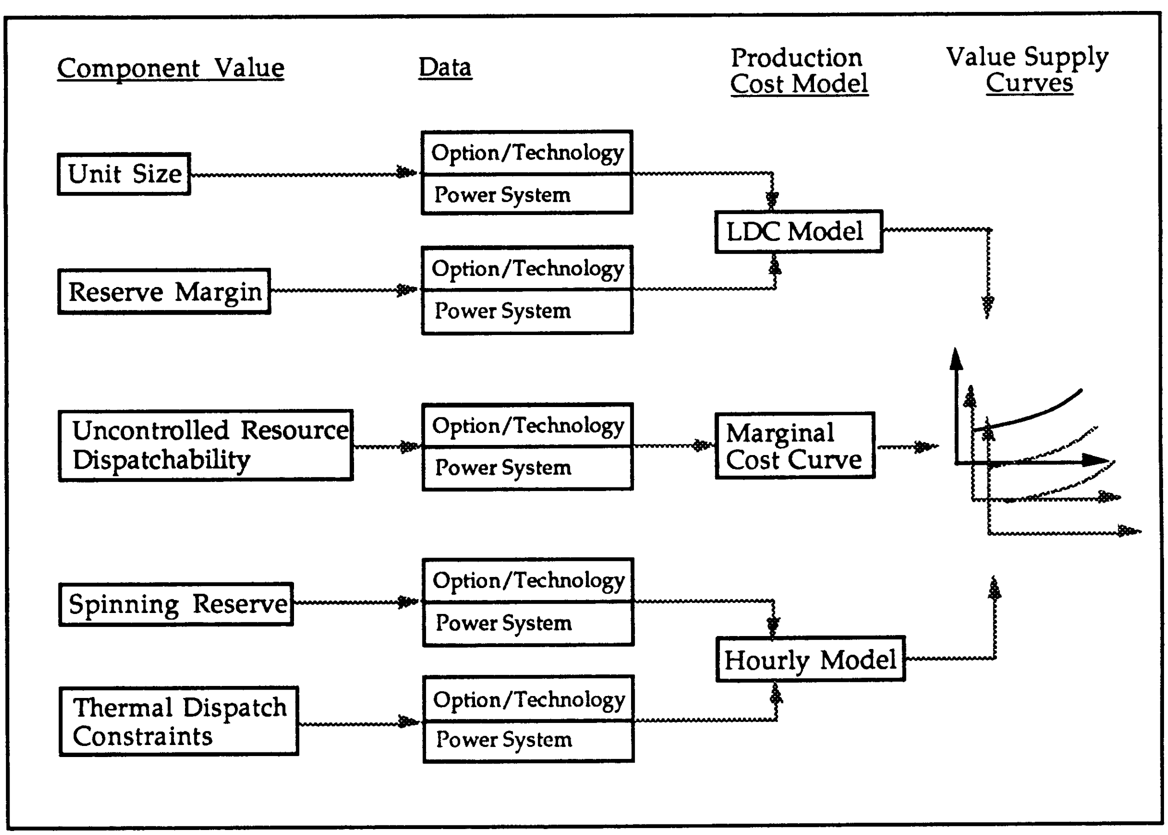
The concern of incorporating global sustainability into local utility planning would extend the methods already mentioned in this section. This could be done by adding attributes to track input and output materials flows, including resource depletion, and relative contributions of virgin and recycled materials. In this context, emissions from fuels produced 'upstream' of the electric utility sector should also be separately tracked to provide a better comparison of emissions across various utility options. If taxes on emissions 'downstream' of generation are considered as an option, then correct economic decision making would mean that upstream emissions should also be taxed and this tax included in the price of fuels to the electric sector.

By individually identifying and explaining individual component values, this chapter puts too much emphasis on their separate analysis. These individual components are aspects of overall system operation and the option and system interaction. Any model that could completely simulate the utility system would calculate all these values, without necessarily quantifying them individually. No such model exists, but current production cost models can evaluate several, as demonstrated in Chapters 4 & 5. The separation of individual component values and the construction of component value supply curves can only be done with the models used by varying only the relevant parameters associated with each value. The point here is that it is less important to uniquely classify and separately quantify these values than it is to identify them and to make sure that they are included in the overall analysis. Only those component values (such as most financial risks) which are excluded from complete production cost modeling will need to be separately modeled and added to obtain full option values.

4.0 Methodology of Evaluating Specific Component Values

The structure of how component values can be based on certain characteristics distinct from individual technologies, the range of component values which have been identified , and how the values quantified may be used and by what parties have been discussed in previous chapters. Five of these generic and quantifiable component values have been chosen as examples to illustrate the process of constructing and evaluating component value supply curves. This chapter describes the methodology and assumptions used to model these component values, including the models used or developed, the choice and range of parameters used to illustrate the benefit supply curve for each component value, and the data for relevant system and technology characteristics. The results of the component value analyses are not given in this chapter, but instead are presented and discussed in Chapter 5 in the same order as they are described below. Figure 4.1 below shows the five component values chosen, the production cost models used to evaluate them, and the flow of the modeling process.

Figure 4.1 - Component Value Modeling Diagram



As shown in this figure, the component values chosen can be evaluated by the use of the system marginal cost curve or by two different kinds of production cost simulation models; either a load duration curve (LDC) model or an hour by hour simulation model. The distinction between the basic methodologies, capabilities and limitations of these two major kinds of models are important and worth discussing, because they determine which is appropriate for modeling different types of component values.

In a load duration curve model, the hourly loads for a year or any sub-period are sorted, and the number of hours spent within a specific load interval or below a specific load level are aggregated to determine the total time spent at different states of system dispatch. The load duration curve can be represented in a piece wise linear way, or by using other mathematical means to describe the probability of being at or below a certain system load level. Generation units are dispatched to meet the different levels of aggregated load, and forced or planned outages which can affect this dispatch may be handled in different ways. In some models, the probability function for time spent at remaining load is recalculated after each unit dispatch by convolving the forced outage rate for the unit with the original load duration probability function. In other LDC models, maintenance periods or forced outage rates may also be handled by derating capacity for the analysis period.

In contrast with LDC models, hourly models proceed sequentially hour by hour through historical or forecast loads, specifically incorporating the sequential information that is lost in a LDC model. As loads change, units are started or stopped in dispatch order as necessary. Units with maintenance outages or dispatch constraints are unavailable, and dispatch skips to the next unit. Outages are handled in a method similar to Monte Carlo simulation, summing results with and without a unit in an average which is weighted using the outage rate. Hourly models require the same basic information about system composition and demand, but typically contain greater detail about unit loading blocks (generation levels below full capacity), and heat rate curves giving efficiency for each loading block. Data is also required for minimum unit run times, unit shutdown times, ramping rates and startup costs.

Hourly models are capable of analyzing detailed dispatch which LDC models cannot, including issues like spinning reserve and unit constraints, but because of the greater detail and chronological approach, hourly models also have significantly greater computational requirements than LDC models for similar time periods. For these reasons LDC models are most commonly used for strategic planning over time periods that run from one year to 20 or 30 years, while hourly models are used for tactical planning or actual dispatch over periods that typically run from days up to a year. Both types of models can trade computing time v. accuracy by modeling a representative sub period and expanding results to a longer time period.

An important effect of the difference in typical time periods is that LDC models have been used more in generation expansion planning, while hourly models have been used more for operational questions. However, some component values which can only be evaluated using an hourly model may also be significant in utility option planning. Part of the goal in using both types of models to evaluate the generic component values presented in this chapter is to compare the relative scale and significance of the two types.

The choice of LDC model for this thesis was both simple and obvious. This thesis stems in part from the study of option and system interactions performed over several years by the Analysis Group for Regional Electricity Alternatives (AGREA) at the M.I.T. Energy Lab for the New England region using the Electricity Generation Expansion Analysis System (EGEAS). This large LDC model was developed by researchers at M.I.T. for the Electric Power Research Institute in 1982, and has become a well accepted industry standard in the US. Although EGEAS incorporates a choice of several methods for optimizing generation expansion plans, the AGREA approach has focused on a multi-attribute, multi-scenario approach which models a broad range of strategies (each composed of a blend of options). Thus, a pre-specified pathway of construction has been formulated for each run. The AGREA team has used EGEAS to model the New England region and study issues ranging from SO2 and NOx emissions, natural gas dependency, repowering, solar and wind power and electric vehicle impacts. The New England project is composed of an advisory group which suggests issues, attributes and key assumptions for each round of analysis. This advisory group includes all the major utilities in the New England region, as well as regulatory, customer, and environmental stakeholders. The AGREA team has developed its EGEAS database in close cooperation with these utilities, as well as from EPRI and other industry sources. This AGREA EGEAS database for the New England region has been regularly updated for each major round of analysis, and was used for all EGEAS modeling done as part of this thesis. The base year for all information in the database is 1994, and system simulations are performed for 1995 on. Obviously, a large (and the most uncertain) part of the assumptions in the database are composed of expected future trends in load growth, fuel prices, capital costs, etc. The component values for reserve margin and the dispatchability of uncontrolled resources were modeled using a 1 year study period (1995) which reduced dependence of the results on these future uncertainties. Analyzing the value of generating unit size was performed using the normal AGREA study period of 20 years (1995 through 2014).

For the evaluation of component values requiring an hourly analysis, several different hourly models were reviewed. The Polaris[17] model developed by Decision Focus Incorporated was selected for several reasons. First, a review of the model documentation indicated that the model could handle the analysis required. Second, the Polaris model is currently used by the New England Power Pool (NEPOOL) for planning purposes, and NEPOOL has a Polaris data base covering all member utilities. Third, Polaris is also used by the New England Electric System (NEES) which agreed to perform Polaris runs on its computer for this thesis. Polaris is not as prevalent compared to other hourly models as EGEAS is compared to other LDC models, and some major New England utility (including Boston Edison) use other models, but the first three reasons were decisive.

For these reasons a request was made to the New England Power Planning Committee for use of the NEPOOL Polaris database. Whereas this database was considered practically in the public domain as recently as a couple of years ago, the trend towards utility competition through deregulation and dis-integration has made this data much more tightly held. For these reasons, a confidentiality agreement was required by NEPOOL and the database was released directly to NEES with the stipulation that all

[17] Decision Focus Inc., *POLARIS Version 1.8*, May 1995, Mountain View, CA.

inspection and use of the data was to be performed on NEES premises. For these reasons, it is impossible to discuss in this thesis the assumptions inherent in the Polaris data as can be done with the EGEAS database. However in the case of the Polaris modeling, all analysis was done for a one year study period (1995), eliminating the impact of future uncertainties. Also, all the key data differences between different Polaris model runs were made exogenously either in system wide parameters or through generic units which were added to the NEPOOL system. Because the AGREA EGEAS database was developed in close collaboration with NEPOOL companies, data in the Polaris database is closely reflected by the data in the EGEAS database.

The heat rate curve data linking efficiency to the generation level for each unit were considered to be the most sensitive information in the NEPOOL database and were removed from the database supplied to NEES. Because these data were omitted and had to be added back, the abbreviated Polaris unit names and block sizes were released. Prior work by the AGREA team using EGEAS to perform limited loading block modeling in 1993 led to the AGREA team receiving the NEPOOL heat rate data which were then available. These older data were matched to the data lacking in the present NEPOOL database, and used where matching units were found. However new unit construction, retirements and refueling meant that there were a significant number of units where data were missing. The largest number of new units were non-utility generators (NUGs). Polaris distinguishes between energy-limited generating units (including hydro units, some power supply contracts, and most NUGs) and demand-limited units (most utility owned, thermal generation units), and the model requires only average heat rates instead of a complete heat rate curve for energy-limited units. The EGEAS database contains average heat rates for all plants, which is public information available on the FERC Form 1 filed by all utilities with the Federal Energy Regulatory Commission. By matching Polaris model names with EGEAS model names, average heat rates were found for all but a few of the missing data in the Polaris database. Finally, the remaining holes in the Polaris database were patched by using data from other plants of similar fuel and size, adapting the heat rate curve to the block sizes of the plants in question. Heat rate curves for generic units in the EPRI Technology

Assessment guide were also examined, but it was felt that a closer match was obtained using the data for similar specific plants as outlined above.

Because of the heat rates omitted in the Polaris database provided by NEPOOL, and the slight differences in heat rate curve data added back to fill this gap, the results of the Polaris modeling below will (as intended) be slightly different than if all of NEPOOL's data could have been obtained and used. Nevertheless, the results obtained from the cases described below and presented in Chapter 5 are believed to be quite close in accuracy. More importantly, the relative scale of the component values compared against each other and the relative impacts of the parameters varied for each component value should be accurate.

In order to understand the reliability of results presented in Chapter 5, it is necessary to understand the reliability and uncertainty of the data and assumptions which are presented in this chapter and used in the analysis. The fundamental data used in this thesis describe the New England power system. These data can be divided into two main categories for the purposes of reliability and uncertainty. The first category is data which describe the currently existing system using real or historic data. This is primarily engineering data and prices contributed by member utilities or summarized by regional organizations, and has a high degree of certainty. The second major category of data in the models describes assumptions about how the system will change in the future, including fuel prices, load growth, unit performance, etc. Obviously these data are less reliable because the future is uncertain, but both categories of data have been accepted as appropriate by other groups. NEPOOL uses the Polaris database in their own modeling, and the regional advisory group containing a wide range of industry participants which assists the M.I.T. Analysis Group for Regional Electricity Alternatives has accepted the EGEAS database for its analytic purposes. One reason for the broad consensus on the assumptions contained in these databases is that they are largely engineering based and used for bottom-up systems modeling purposes.

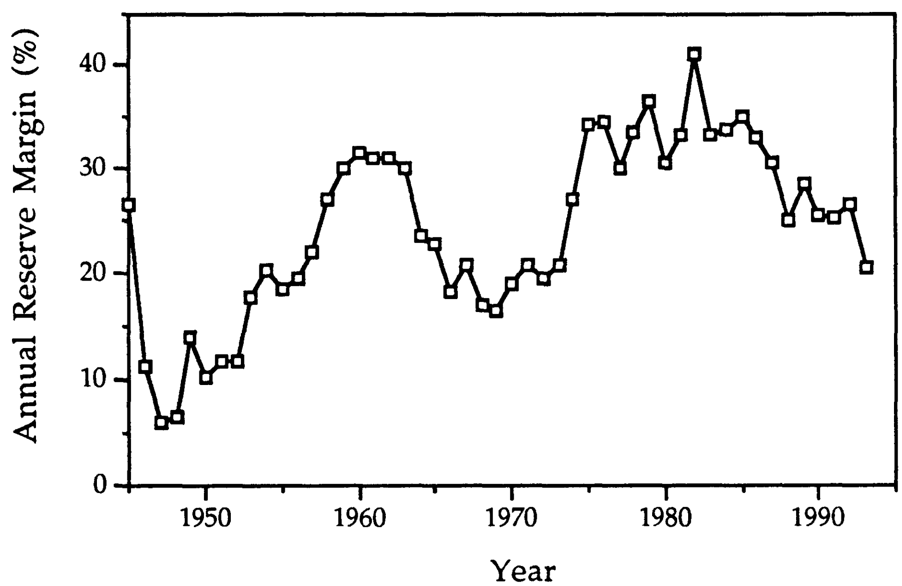
Having said this, it is important to point out that four of the five component values analyzed were modeled using only the base year 1995. This means that they were based on existing rather than projected data, and should be quite reliable. Only the value of unit size was analyzed using a 20 year modeling period, because it was necessary to look at additions of generating capacity over time. The key assumption in system data required for this analysis is load growth over time, and as described below in Section 4.3 the NEPOOL base case load growth scenario was used. The nuclear technology characteristics which are most important are unit size, capital cost, capacity factor and dispatch cost. The utility system is complex and non-linear in the way it transforms assumptions into results, so sensitivity analysis was used to analyze these factors. In fact, the basic concept of finding value supply curves for unit size is a sensitivity analysis of the impact unit size has on capital cost, so the first two factors are addressed directly by this thesis. Sensitivity analysis has also been done on the capital cost of the competing ALWR technology which is fixed in size. Sensitivity analysis of dispatch cost and capacity factor are discussed and presented with the other results in Chapter 5.

Finally, it is important to note that the thrust of this thesis has been to analyze the benefits which derive from certain component sources of value, and not upon the cost of the options which provide them. For example, the value of storage in shifting PV or wind generation is based solely on the spot price value of electricity at low v. high load hours, and not upon the cost of PV or wind generation. This thesis does discuss some costs for storage and compare them to its benefits, but the real thrust is aimed at finding a benefit supply curve rather than individual option cost curves, which industry participants will need to make their own decisions. With dispatch options like spinning reserve level, the cost of implementing an option may be essentially zero, and the value supply curve associated with different spinning reserve levels must be compared to the costs of different levels of reliability.

4.1 Reserve Margin

As previously outlined in Chapter 3, the reserve margin of a utility system has a significant value, based on the reliability it supplies. This value depends upon the reliability and diversity of the units which make up the system, the size of the reserve margin (and hence which plants are or are not dispatched), and the value of reliability to the customers. Reserve margin also has a cost based on the need to recover capital investment in all plants, including those which are only lightly used. Historic reserve margins for investor owned utilities during the period from 1945 through 1993 are shown below in Figure 4.2. As can be seen, the average national reserve margin has varied significantly, with a low of 6.1% in 1947, a high of 41.0% in 1982, and an average of 24.4% over this 49 year period.

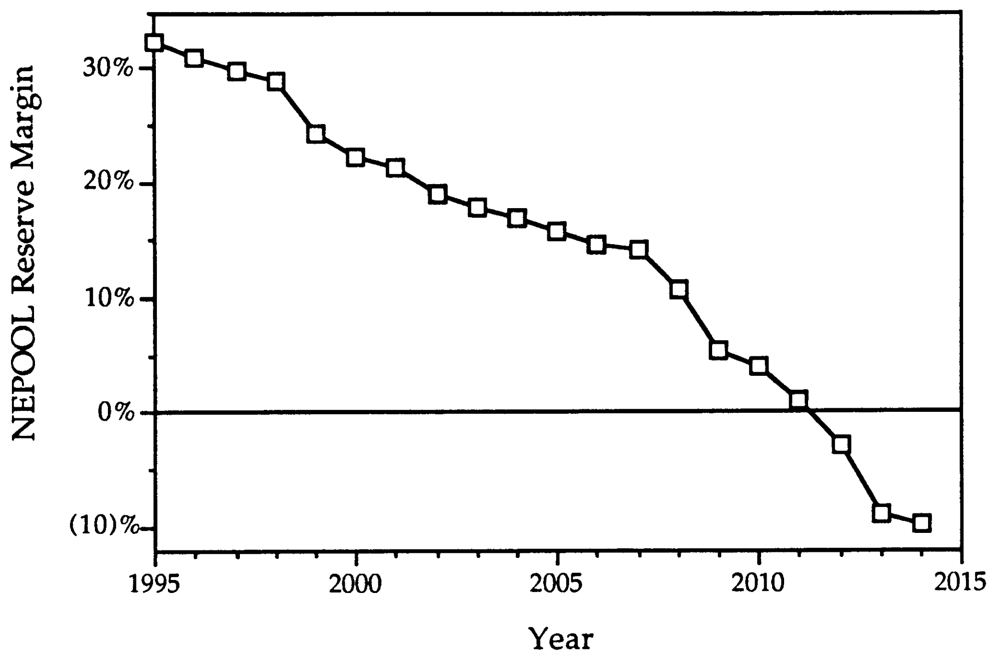
Figure 4.2 - Historic US Reserve Margins for Investor Owned Utilities



Although it is much harder to track the historic performance of national average reliability associated with these reserve margins, it is clear that reserve margins of 15% to 20% have been historically considered adequate, or else generation would have been constructed to raise the reserve margin. The reserve margin standard which utilities have used as a guideline, or claimed as necessary for adequate reliability has also varied over time, although it is difficult to determine whether this standard is leading or trailing the actual physical reserve margin.

For the NEPOOL system, the reserve margin was 32.3% in 1994. This is projected to decrease over time due to projected load growth, and presently committed capacity additions and retirements as shown in Figure 4.3 below.

Figure 4.3 - NEPOOL Reserve Margin Trajectory



This figure is based upon a projected demand growth which incorporates NEPOOL's base case projection of DSM savings and which is used as the reference base case for AGREA modeling using EGEAS. As can be seen by comparison with the graph of the historical national average above, the current NEPOOL reserve margin is relatively high by historic standards, reflecting lower load growth rates and significant increases in NUG capacity over the recent past. As can be seen, the reserve margin based on projected base DSM load growth declines to approximately 20% by the year 2001, and new capacity will be required before 2005.

In order to determine the net value of reserve margin in an existing system it must be compared with an alternate system that has a higher or lower reserve margin. The problem lies in choosing the composition of this alternate system. In the current environment of deregulation and disintegration, the most interesting alternate system with decreasing reserve margin would be achieved by removing plants according to their competitive free market value (per MW capacity), from most to least expensive. This free market value does not yet exist because the market does not (quite) yet exist, but it can (and will) be found by calculating the net present value of the projected future net revenues (sales minus variable and fixed costs) for each plant. This calculation is of intense interest as New England proceeds towards deregulation and competition. One of the key questions therefore is how sunk capital costs for the system may be allocated, and in particular if they may be allocated as fixed costs to existing plants.

Instead the issue of reserve margin was framed in two other, alternate ways. The first question asked was, "What is the value of the present NEPOOL system, compared to another system identical except in the amount of generating capacity?" Such a system would have the same number of plants, with the same characteristics including efficiency, fuel diversity, etc., except that all units (including purchases) would have their size multiplied by a single fraction sufficient to reduce the NEPOOL reserve margin to some target reserve margin. This capacity multiplier was chosen as the parameter to be varied for the first set of reserve margin cases, and is shown in Table 4.1 below, as reserve margin decreases from 30% to 5%.

Table 4.1 - Capacity Fractions for Reserve Margin Valuation

Reserve Margin	32.3%	30%	25%	20%	15%	10%	5%
Capacity Multiplier	1.000	0.982	0.945	0.907	0.869	0.831	0.793

Reserve margins below 15% or so seem unrealistic with the present system, but they were evaluated for comparison purposes. Future trends which may decrease the need for reserve requirements would include more reliable, smaller, lower maintenance and diverse generating technologies (e.g. combined cycle combustion turbines and fuel cells), and growth of interruptible loads. Whether these factors may overcome the increasing need of existing large and aging plants for a certain level of reserve margin is uncertain, and the type and age of plants which survive in a competitive market may determine the balance which is struck.

A system with a fractionally smaller generation capacity will require less future revenue to recover capital costs. Because system composition remains unchanged except for size in this case, it is possible to apply the same capacity multiplier fraction to NEPOOL capital recovery requirements. To find these requirements it is necessary to look at NEPOOL's projected base revenues[18], which are revenue requirements associated with existing and assumed future plant as given by the NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission (the CELT report)[19]. These revenues cover all fixed costs, including fixed O&M costs, pollution control costs, capital recovery costs, transmission and distribution costs, and general and administrative (G&A) costs. They also cover future power purchases and non-utility generation.

The cost of future capital cost requirements had already been calculated for prior AGREA EGEAS modeling by subtracting out forecast costs for fixed O&M, pollution control costs (at the 1995 RACT standard), T&D expenses, and G&A costs. The remaining capital recovery costs include existing and forecast utility generation capacity, non-utility generation capacity, power purchases, and T&D capital expenses, with a 1995 value of $6.063 billion and a net present value of $68.29 billion (in 1995 dollars) over the 20 years from 1995 to 2014. All of these costs would be proportionately smaller for a power system with lower reserve margin, except for the T&D capital expenses.

To separate T&D costs from this estimate of future capital recovery costs, it was necessary to find the what fraction T&D is of total electric utility plant. The Edison Electric Institute collects this information from Energy Information Administration for all US investor owned utilities, as shown in Table 4.2 below[20].

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18 NEPOOL Load Forecasting Committee, NEPLAN Staff, *NEPOOL Electricity Price Forecast for New England*, 1994-2009, Appendix A, Exhibit 13, April 1994.
19 The New England Power Pool, *NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission*, 1993-2008, April 1, 1993.
20 Edison Electric Institute, EEI Financial Info, *Construction Expenditures Survey 1995*, July 5, 1995.

Table 4.2 - Gross Existing 1993 Investment in Electric Utility Plant by US Investor Owned Utilities.

	$ Billions	Percent of Total
Steam	128.7	23.1%
Nuclear	143.5	25.8%
Other	19.5	3.5%
Total Generating Plant	291.7	52.4%
Transmission	59.0	10.6%
Distribution	139.7	25.0%
General & Miscellaneous	46.8	8.4%
Nuclear Fuel	20.0	3.6%
Total Electric Utility Plant	557.2	100.0%

It is interesting to note the sheer scale of total investment in the electric utility sector, which is over half a trillion dollars by 1993. The gross investment shown is not decreased for depreciation and is the sum of mixed dollar investments from all past years. What is needed are the total percentages after depreciation, but these are difficult to obtain. The gross percentages seem approximate since the summation over many years reduces the effect that year to year fluctuations in capital expenditures and inflation may have on the depreciated totals. The fraction of T&D capital for the utility sector as a whole will be somewhat larger than shown above, since investor owned utilities sell to other utilities (like municipals and rural electric cooperatives) whose primary physical capital is in T&D. However NEPOOL is composed of investor owned utilities so these numbers are appropriate.

The $6.063 billion of 1995 capital recovery requirements derived from NEPOOL data have already been reduced for general and miscellaneous expenditures, and the NEPOOL data does not explicitly include nuclear fuel costs (although these are commonly capitalized), which together sum to 12% of the EEI gross investment figures. Therefore the relative ratios for the NEPOOL capital recovery requirements are 59.5% generating plant, 12.0% transmission plant, and 28.5% distribution plant. Therefore the 1995 NEPOOL capital recovery requirements for generating plant which could be reduced by fractional unit capacity is $3.607 billion. It should be remembered that this number is reached by applying a national T&D percentage to a regional capital recovery total, and if New England varies from the national average in its need for T&D capacity there may be some error. As a check, the

FERC Form 1 for Boston Edison only gives T&D investment as 44% of total depreciated generation and T&D capital.

The second method of addressing the question of reserve margin in a less general way was posed by reducing the number of nuclear generating units in operation. Anti-nuclear sentiment expressed through debate on issues involving pressure vessel embrittlement and license renewal makes the issue of possible nuclear retirements relevant. This case is instructive because reducing the reserve margin by reducing the number of nuclear baseload units measures the cost of losing base load energy with the second lowest variable dispatch cost (next to hydro).

Existing nuclear plants have a depreciated capital cost balance in the utility's ratebase which must still be recovered. If this future capital recovery cost is ignored, then the question is basically "what if this plant were never built," whereas if this future cost is considered then the question is "what if this plant is retired?" In the case of retirement, or under the scenario of impending deregulation, the most controversial question is how these future stranded costs will be shared or allocated between customers and stockholders, but from an overall societal point of view the cost to be born is still the same.

This thesis poses the first question, by removing existing nuclear units as though they had not been built, so that their capital cost requirements are removed. This has been done in order of the plant's ages, as shown in Table 4.3 below. The oldest plant (Yankee Rowe) has already been retired, so it was not included, and the youngest plant in the New England Region (Seabrook) was not removed because it would have reduced the reserve margin below zero. It is an artifact of the New England system that these nuclear plants each represent a 3% to 6% reduction in reserve margin, so that the steps in reducing the reserve margin in this case roughly parallel those in the first, fractional capacity reduction approach.

The future capital cost recovery requirements which are shown below are based on information from the 1995 FERC Form 1's filed by the companies owning the nuclear plants. These forms were downloaded in electronic form from FERC's electronic bulletin board, and include comprehensive financial data on the utilities which file them. In order to find the future capital cost recovery requirements it is necessary to know the original cost minus the amount of depreciation, which is also called the embedded cost. The embedded cost minus the value of the stream of future revenues from the plant is the stranded cost. The relevant data from the subsections of the FERC Form 1 were the original cost of plant in service (Form 205g) and the cumulative depreciation (Form 219b). These data are subdivided by categories, including steam fossil and nuclear investments, but are not divided by individual plants. The individual plant data given in Form 402 include original cost, but do not include depreciation. This means that it is easy to find the embedded cost for utilities that only own one nuclear reactor, but much more difficult to apportion the total cumulative depreciation between several plants.

Fortunately, four of the seven plants in question are wholly owned either by one company (Pilgrim, owned by Boston Edison), or by holding companies that have shared utility ownership, but file separate FERC Form 1's (Connecticut Yankee, Maine Yankee, and Vermont Yankee). The oldest plant considered (Connecticut Yankee) began commercial operation in 1967 and the original cost was exceeded by cumulative depreciation ($350.9 and $353.7 respectively). This is possible because retired equipment decreases the original cost, but the embedded cost given in Table 4.3 below.

The remaining units Millstone 1, 2 and 3 are owned by Connecticut Light and Power (81%, 81%, and 52.933%) and nine other minority owners. By using a database from Mr. Gene Fry of the Massachusetts DPU, the original and annual costs of the Millstone units were depreciated using straight line depreciation over the remainder of the 40 year book life of the plants. This produced estimates of total original cost, total cumulative depreciation and total embedded cost which were within 6.1%, 10.4% and 15.2% respectively of the FERC Form 1 totals after correcting for the Connecticut Light and Power ownership share. The individual unit costs were adjusted proportionately so that their totals agreed with the FERC Form 1 data, producing the embedded cost (or depreciated capital cost) shown in Table 4.3 below. Because of the assumptions and adjustments just described there may be some small error in these embedded costs, but they are believed to be reasonable estimates.

Table 4.3 - NEPOOL Individual and Cumulative Nuclear Capital Recovery Requirements

Name of Plants Retired	Year Installed	Depreciated Capital Cost (M$)	Cumulative Reduction (M$)	Plant Capacity (MW)	Cumulative Reduction (MW)	Reserve Margin
None	n/a	0	0	0	0	32.3%
Connecticut Yankee	1967	0	0	600	600	29.4%
Millstone 1	1970	150	150	662	1262	26.2%
Pilgrim 1	1972	744	894	678	1940	22.8%
Maine Yankee	1972	190	1084	890	2830	18.5%
Vermont Yankee	1972	149	1233	563	3393	15.7%
Millstone 2	1975	365	1598	910	4303	11.3%
Millstone 3	1986	2555	4153	1253	5556	5.1%

In both cases, reductions in system reserve margin were modeled using the EGEAS model for a 1 year study period (1995). No other assumptions were changed from the base AGREA EGEAS database other than those fractional deratings or retirements outlined above. As noted above, the one year study period eliminates uncertainty based on forecasts, trends or predictions. The one year study period also illustrates the fact that the value of reducing the reserve margin is based on the state of the overall existing power system rather than any single technological option added to it. The value is subject to change depending upon the composition of the generation mix, and the flatness of the load duration curve. Conversely the benefits of reducing the reserve margin can be claimed by any new technology which allows system operation with a lower reserve margin.

The results of the analyses for the two reserve margin cases described above are presented and discussed in Section 5.1 of Chapter 5.

4.2 Unit Size

As outlined in Chapter 3, the value of unit size in new construction compared to the rate of system load growth may have a significant value, based upon the key unit characteristics of unit size and cost, and the key system characteristics of load growth, existing reserve margin, and the supply curve of dispatch costs..

In order to evaluate the value of unit size, it was necessary to choose a modular technology where multiple units could be added either all at once or gradually over time. Although some new gas-fired technologies like combustion turbine combined cycle units can be considered modular, the modular high temperature gas reactor (MHTGR) was chosen for several reasons. First, this value is related to front loading capital costs for capacity that is not initially needed, and nuclear units have high capital cost. Second, nuclear reactors have always been the largest single thermal units so they have been particularly prone to this particular diseconomy of scale. This makes the advantages of a modular nuclear reactor particularly interesting. Third, a conventional choice for the next generation reactor (advanced light water reactor or ALWR) can be compared to the MHTGR, and the benefits of the modularity can be compared to the other relative benefits of the two nuclear technologies.

The advanced light water reactor is an evolution of existing light water reactor technology, with improvements in safety and reduced cost due to standardized design and simplified systems. In contrast, the MHTGR is a marked departure from current reactor design, although several older MHTGR designs have been built as test reactors with varying degrees of success. Modern MHTGR designs are built around a fuel where the uranium is encased in a graphite matrix instead of having a uranium oxide pellet encased in a zirconium tube. The graphite fuel moderates neutron speed with negative thermal feedback, and the high heat capacity provides safety from decay heat during a loss of coolant accident. The graphite fuel is cooled by helium which may be used either to boil water in an intermediate heat exchanger for a conventional steam cycle, or used directly in a Rankine cycle to drive a high temperature gas turbine. With regeneration, the most advanced designs can reach thermal efficiencies of 47% (equivalent to a heat rate of 7262 Btu/kWh). The MHTGR is a constant temperature design, so that as power drawn from the reactor increases the core temperature drops and the negative thermal feed back increases reactivity and power output. This response time is equivalent to that for modern combustion turbine generating units. The fast response time and high efficiency are significant advantages over conventional reactor designs.

The generic characteristics for the ALWR were taken from the 1993 EPRI Technology Assessment Guide. Based upon consultation with Dr. Lawrence Lidsky of the M.I.T. nuclear engineering department, the MHTGR design chosen for this thesis was a General Atomics reference design. This design was part of a study performed by a consortium of engineering firms and the Oak Ridge National Laboratory for the Department of Energy[21]. This work covers three reference designs, including the MHTGR-SC (Steam Cycle), the MHTGR-GT/IC (Gas Turbine/Indirect Cycle), and MHTGR-GT/DC (Gas Turbine/Direct Cycle). Cost estimates for these three designs are provided at three different points along the learning curve; prototype cost, replica cost, and final target cost. For the purposes of this thesis, the final target cost for the most advanced direct cycle high temperature gas reactor was chosen. The primary characteristics of both the ALWR and MHTGR technologies are shown below in Table 4.4

Table 4.4 - Primary Characteristics of ALWR and MHTGR Reactors

Reactor Technology	ALWR	MHTGR
Fuel	Uranium Oxide	Graphite Block
Plant Life (years)	30	30
Rated Capacity (MWe)	1360	170
Equivalent Forced Outage Rate (%)	17.2	10.5
Full Load Heat Rate (Btu/kWh)	10200	7070
Capital Cost (94$/kWe)	1370	1800
Fixed O&M (94$/kW/yr)	63.61	33.56
Variable O&M (94$/MWh)	0.316	0.966
Fuel Cost (94$/MBTU)	0.550	1.324
Dispatch Cost (94$/MWh)	5.93	10.33

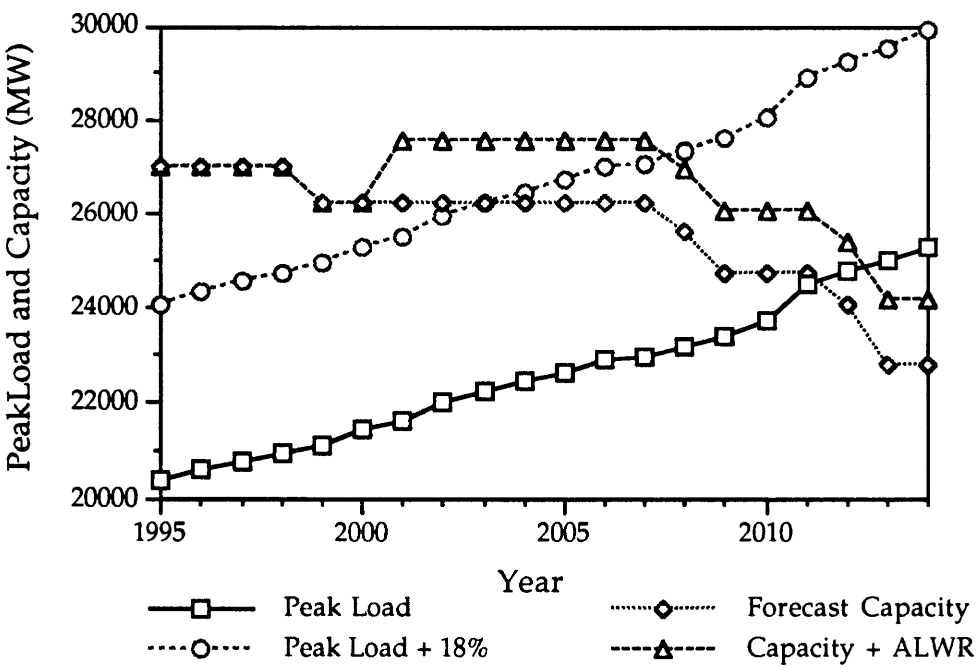
Several comments are appropriate, based upon this choice of reactors. First, the analysis was performed on a 'what if' basis, so that the time required to build sufficient units to reach the final target price was ignored. Second, the capital costs are overnight construction costs, including an allowance for contingencies but no interest charges since these are calculated in EGEAS

21 ABB/Combustion Engineering, Inc., Bechtel National, Inc., Gas-Cooled Reactor Associates, General Atomics, Oak Ridge National Laboratory, and Stone & Webster Engineering Corp., *Modular High Temperature Gas-Cooled Reactor Commercialization and Generation Cost Estimates*, DOE-HTGR-90365, issued by Gas-Cooled Reactor Associates, September 1993.

based on the construction expenditures trajectory. For the MHTGR, the 1800 \$/kW cost is based on 4 170 MW units being built at the same time. Third, the reference reactor design incorporates a graphite block fuel, rather than a spherical pebble bed fuel. This was based upon the choice of the General Atomic company which participated in the design study, and happens to have a patent upon this particular fuel design. However, conversation with Dr. Lidsky indicates one expert opinion that the pebble bed fuel is more likely to succeed in actually being built. Nevertheless the costs in this design study were used because of its cost detail, the recent date of the design, and the fact that fuel fabrication is a relatively minor fraction of overall cost. Fourth, there is some uncertainty in the assumed design characteristic values shown above, and the sensitivity of the results to changes in dispatch cost and equivalent forced outage rate (EFOR) is discussed in Chapter 5.

Since the value of unit size is relative to system load growth (in absolute units of MW/year instead of %/year), it was necessary to inspect the need for future capacity additions in the NEPOOL service territory. The trajectory of future capacity needed, based upon predicted load growth and an 18% reserve margin are show below in Figure 4.4

Figure 4.4 - Future Capacity NEPOOL Need Trajectory



As can be seen in this figure, the current reserve margin of 32.3% shrinks to 21.2% by the year 2001. Adding a 1360 MW ALWR plant in the year 2001 increases the reserve margin to 27.5% in that year, which then decreases to 20.1% in 2007 and 16.4% in 2008. Using the target reserve margin of 18% shown in the figure above therefore gives an 8 year window during which no major additional capital construction would be necessary. The MHTGR design module size is 173 MW, or approximately one eighth of the size of the ALWR. By adjusting the MHTGR module size to 170 MW, it was then possible to compare the ALWR to eight MHTGR modules built in the same year (2001), four MHTGR modules built every four years (2001 and 2005), two MHTGR modules built every two years (2001, 2003, 2005, and 2007), and eight MHTGR modules built every year from 2001 through 2008.

The reference design selected assumes that four individual MHTGR units are built on a single site. These four units share common facilities and costs, including land, electrical switchyard, some buildings, etc. The average cost/kW for all four units was used for the four cases described above, since this gives the value associated with a geometric decrease in unit size. A more realistic option would be to attribute common costs to the first of every four units. This would represent an intermediate case because it would restore some of the capital cost front loading which the modularity is used to avoid, and would make a difference only in the two cases where the modules are constructed singly or in pairs. Unfortunately, the reference design report does not break down its costs by common v. individual items, but instead breaks down costs by different technical subsystems. In an effort to provide this more realistic but less certain comparison, the cost of land, structures, and electrical plant were allocated to the first unit of every four. Table 4.5 below shows the major subsystems, this allocation, and the difference between the average cost and the cost for unit 1 v. units 2, 3 and 4. For the two cases where this allocation occurs all other MHTGR assumptions were retained unchanged.

Table 4.5 - MHTGR Costs for Average, First, and Follow-on Units

MHTGR Target Plant Costs (Gas Turbine Direct Cycle)	Units 1-4 (94 M$)	Unit 1 (94 M$)	Units 2-4 (94 M$)
Land & Rights	2	2	0
Structures & Improvements	136	136	0
Reactor Plant Equipment	486	121	121
Turbine Plant Equipment	129	32	32
Electric Plant Equipment	56	56	0
Misc. Plant Equipment	32	8	8
Heat Rejection System	28	7	7
Total Direct	870	363	169
Construction Services	106	27	27
Home Office Engineering	68	17	17
Field Office Engineering	48	12	12
Owner's Costs	169	42	42
Total Indirect Costs	391	98	98
Base Construction Costs	1261	460	267
Contingency (50% confidence)	302	110	64
Overnight Construction Costs	1563	571	331
Total Cost (94$/kWe)	1800	2630	1524

The capital costs of the MHTGR and ALWR designs are shown above in Table 4.5. Both are overnight costs, including an estimated contingency cost which is based on a 50% confidence level. This means that these costs may not be the single most probable value, but the chances are estimated to be 50/50 that the final cost will be either higher or lower. The capital cost of the reference ALWR design taken from EPRI was lower than the MHTGR cost, and arguably lower than the actual cost might be. Because of this, a final case was also modeled where the cost/kW of the ALWR was raised to be the same as that for the MHTGR. In this way, the differences between the two designs could be determined, based upon the fuel cost, efficiency, and dispatch. Construction periods for both the ALWR and MHTGR technologies were given by the stated references as 5 years. In order to model the present value of the capital cost streams, it was necessary to assume a construction cost trajectory over this period. Both the references omitted such a spending trajectory over time, and so a typical generic trajectory was selected from the AGREA EGEAS database, with expenditures of 1%, 1%, 4%, 44%, and 50% of the total cost during years one through five respectively. The real discount rate of 7%, and the projected trajectory for the assumed rate of inflation were also both taken from the AGREA EGEAS database.

The final set of 8 cases modeled is summarized below in Table 4.6.

Table 4.6 - Summary of Unit Size Cases Modeled

Case	Reactor Technology	Capacity (MWe)	Cost ($/kW)	Number of units coming on-line in each year							
				2001	2002	2003	2004	2005	2006	2007	2008
1	ALWR	1360	1360	1							
2	ALWR	1360	1800	1							
3	MHTGR	170	1800	8							
4	MHTGR	170	1800	4				4			
5	MHTGR	170	2630	1				1			
	MHTGR	170	1524	1		2		1		2	
6	MHTGR	170	1800	2		2		2		2	
7	MHTGR	170	2630	1				1			
	MHTGR	170	1524		1	1	1		1	1	1
8	MHTGR	170	1800	1	1	1	1	1	1	1	1

All eight cases were modeled with EGEAS for a 20 year period. To maintain the target system reserve margin of 18% from 2008 through 2014, additional capacity was needed. This capacity was chosen to be a blend of natural gas fired advanced combustion turbine (ACT) units and advanced combined cycle (ACC) units in a 20/80 ratio of total capacity. The number of both ACT and ACC units for each year was chosen to meet the minimum reserve margin and the capacity ratio as shown below in Table 4.7. This same construction trajectory was used for all eight cases discussed above.

Table 4.7 - Non-Nuclear Capacity Fractions and Construction Trajectories

Technology	ACT	ACC
Capacity (MW)	40	250
Target Capacity Fraction	20%	80%

Year	Capacity Needed (MW)	Number of Plants Built		Total Built (MW)	Fraction of Total Capacity	
		ACT	ACC		ACT	ACC
2008	362	3	1	370	0.324	0.676
2009	1562	5	4	1570	0.204	0.796
2010	1961	4	1	1980	0.242	0.758
2011	2816	2	3	2810	0.199	0.801
2012	3820	2	4	3890	0.165	0.835
2013	5353	12	4	5370	0.209	0.791
2014	5700	2	1	5700	0.211	0.789

Legend: ACT = Advanced Combustion Turbine
ACC = Advanced Combined Cycle

Based on the plant characteristics and construction trajectories described in this section, all eight cases were modeled using the EGEAS model and the existing AGREA EGEAS database. The results of this modeling are presented and discussed in Section 5.2 of Chapter 5.

4.3 Dispatchability of Uncontrolled Resources

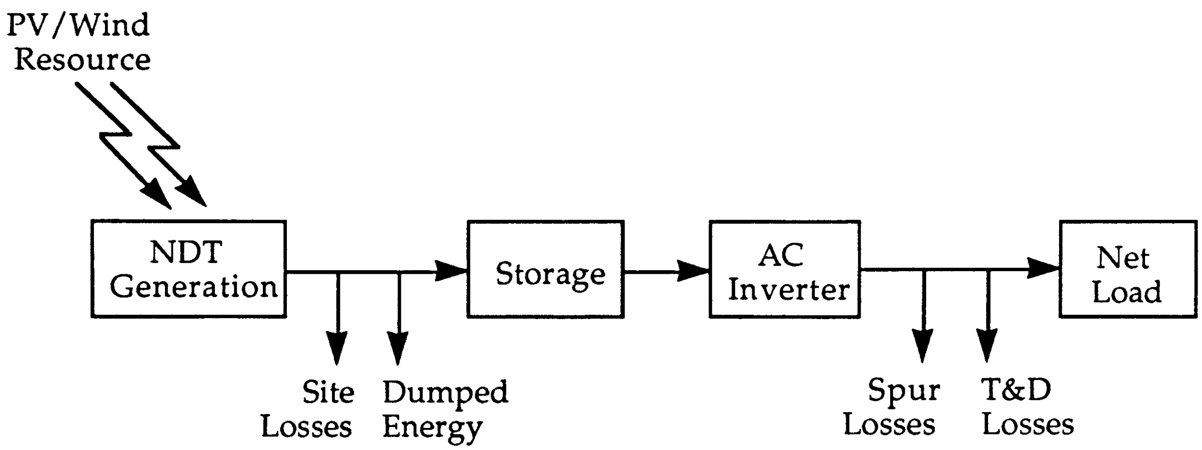
The value of adding dispatchability to an uncontrollable generation resource has been theoretically outlined in Chapter 3. As described there, the way to add the value of dispatchability to an otherwise uncontrollable resource is by placing intermediate storage between the generation and the system grid. This section describes the renewable resources chosen for evaluation, how the range of storage was defined, the addition of inverter capacity as a variable to be evaluated, the development of the model used to optimize the use of the storage capacity, and the way in which the system impacts were modeled.

The most common renewable resources generally have several inherent faults; they are diffuse, often remote, and the availability over time is uncontrollable. These drawbacks can be overcome by investment, but the question is generally how much capital cost can be balanced against the use of a resource that has no direct cost. In the case of the most widely used renewable resource, dams both concentrate and store the hydropower energy in a way that is cost effective. In the case of wind and solar power, energy concentration at the most favorable locations is diffuse, and the benefits of storage to match weather-based electricity generation to system load patterns have not been economic.

This thesis has chosen to evaluate the value of adding different levels of storage and inverter capacity to both wind and photovoltaic generation. This creates a family of supply curves for the benefits of storage and inverter capacity for each of these two different resources. These curves show how the total amount and value of generation depend upon both the resource and the amounts of storage and inverter capacity chosen.

For both wind and photovoltaic generation, the succeeding links in the chain from resource to load are illustrated in the schematic diagram in Figure 4.5 shown below. Each resource has an hourly pattern which is based on the year and location of the data chosen. Each generation technology has a given raw capacity size and on-site conversion losses. Power from the NDT generation goes into storage, and when it is withdrawn must be converted to the correct voltage and wave form by a semiconductor inverter. The amount of storage and inverter capacity for transmission are parameters to be varied, and depending upon these capacities some generation may be dumped because it cannot be used. Finally transmission and distribution losses depend upon resource location, and the net load to be met by other generation resources depends upon hourly system load and the optimal use of the storage.

Figure 4.5 - Schematic Diagram of
Variable Dispatch Energy Flow



The key characteristics of both the wind and photovoltaic technologies chosen are given below in Table 4.8. The technology capacity, location, year of resource data, and losses are exogenous input data, while the peak day and total annual generation and capacity factor are results presented here for comparison. While the generation technologies are explicit, the means of storage has been left completely general and unspecified. Although battery storage seems the most likely current option, any future storage technology could produce the same cost benefits. No costs are listed in Table 4.8 below for either the PV or wind generation or for the energy storage because they are not relevant to finding the benefits of storage, which depend only upon the ability to shift generation from hours with low marginal system costs to hours with high marginal system costs. This means that the benefits of storage presented in Section 5.3 are independent of the uncertainty in generation costs. However, the benefits of storage are compared to the costs of battery storage (the most likely technology) and inverter capacity.

Table 4.8 - NDT Generation Data

	Photovoltaic	Wind
Generation Capacity (MWe)	1000	1000
Resource Location	Boston, MA	Longfellow Mountains, ME
Year of Resource Data	1968	1990
Site Losses (%)	10	15
Spur Losses (%)	0	10
T & D Losses (%)	2	10
Max. Day's Generation (MWh)	5,564	6,652
Annual Generation (MWh)	768,983	841,353
Capacity Factor (%)	8.8	9.6

Note: Maximum day's generation is net of site losses but not of T&D or spur losses.

The primary source of the technology and resource descriptions used for this analysis are previous research work done at the M.I.T. Energy Lab[22]. This includes the choice of generation technologies, the resource to generation conversion curve for the wind turbine chosen, the raw data for the hourly resource data at the locations given, and the various losses shown above. These losses deserve explanation because of their differences. The site losses are specific to the resource and technology. The wind resource was situated at a remote location requiring a spur transmission line to reach the rest of the grid, so an extra transmission loss was added to the normal T&D loss. In contrast, the photovoltaic generation is distributed at a low level in the distribution system so the normal T&D losses are reduced for this technology.

The choice of 1000 MW of raw generation capacity (before site losses) for both solar and wind resources was based on the need to produce a discernible impact on a system with approximately a 20 GW peak load. A smaller amount might have been sufficient if only the gross impact were considered, but for comparison over a range of storage capacity it was necessary to be able to determine cost changes due to an optimized shift in the load duration curve, while keeping the total annual generation constant. On

[22] Cardell, Judith B., *Renewable Energy Technologies in the New England Electric Sector*, MIT Energy Lab Working Paper MIT-EL 94-002WP, June 1994

the other hand, the renewable generation needed to be kept small enough that it did not affect the relative dispatch of the rest of the system. The 1000 MW level of capacity for 1995 was postulated without worrying whether the rate of market penetration would be feasible (especially since this is written in 1996). However the total capacity size is less than the 1500 MWe judged to be reasonable in the prior work[23], albeit with a more gradual and reasonable 10 year penetration rate from 1995 through 2004.

The raw PV and wind resource data were gathered during the previous work cited, where the analysis was performed over a 20 year study period. Where fewer years of resource data were available, the 'weather' was repeated to fill the entire period. However the present analysis was performed only for the year 1995 for two reasons. First, the benefits of storage are likely to change slowly as load patterns shift due to customer trends and DSM. Second, the burden of optimizing storage dispatch for a full twenty years was both onerous and unnecessary for the purposes of illustrating storage valuation. The question was then how to pick a single representative year from both the wind and solar data available. Averaging hourly loads across the years of data was inappropriate since this would reduce the hourly variability of the resources, and change the value of the storage used. Instead, a simple program was written to calculate the total annual generation for each year. The years were ranked by their generation and the median year was chosen. For the photovoltaic data the year 1968 was chosen, and for the wind data the year 1990 was chosen. The annual variability of these resources, their average, and the range of plus or minus one standard deviation are shown below in Figures 4.6 and 4.7.

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[23] Cardell, p. 26.

Figure 4.6 - Variability in Annual PV Generation

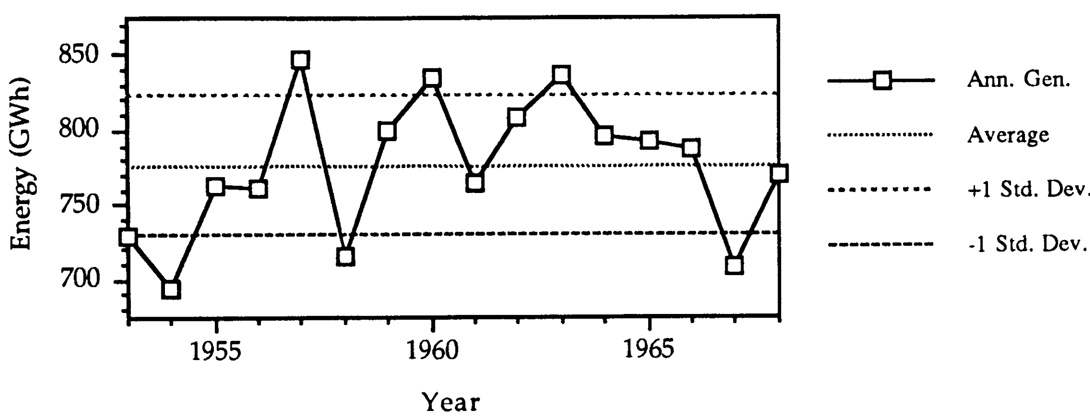
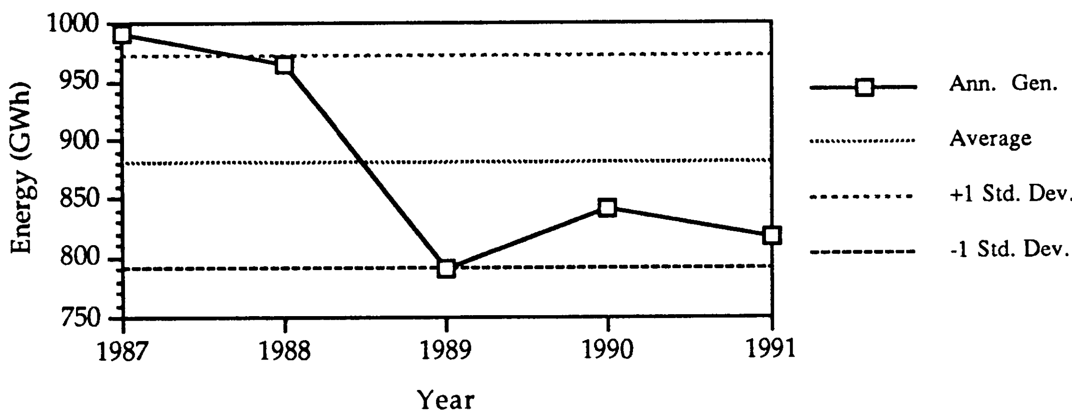


Figure 4.7 - Variability in Annual Wind Generation



The 1995 hourly system load file used was taken from a 20 year hourly load file obtained from NEPOOL for prior work by the AGREA team. This file incorporates an assumed load growth rate and a base, reference trajectory of DSM penetration. The present research used only the 1995 hourly data, so that projected trends had effect.

The value of the benefits due to storage increase with the amount of storage available (more is better!), until diminishing returns set in and a maximum benefit is reached. However, the index or measure of this scale is not predefined. Clearly the scale begins at zero and could go (non-economically) to infinity. Several measures of storage were considered. The first was the number of gross MWh of storage capacity. To make this measure comparable between units of different capacity, it can be transformed to the number of hours of generation at peak capacity which can be stored (i.e. MWh/MW = hr.). This measure is better, but does not include any consideration of the resource shape due to diurnal and seasonal variation. For this reason, storage was instead chosen to be measured as a fraction of the peak day's generation for 1995 for both wind and photovoltaic plants.

Likewise, the choice of an index for the amount of inverter capacity is not pre-defined. The most obvious choice would simply be MW of inverter capacity, but this is not a generic measure that can be used for comparison between installations of different size. Instead, inverter capacity was measured as a percentage of the net NDT generation capacity, after on-site losses have been subtracted.

Once the amount of storage and inverter capacity are chosen, the problem is clearly how to optimally transfer the energy generated during low value hours where low system load means low marginal generation costs to high value hours where high system load means high marginal generation cost. An optimization based on the marginal generation cost would be complex, because the marginal cost is a non-analytic function depending upon system composition that changes over the year with scheduled maintenance, fuel switching and other factors. Even at any one instant it is a step function, where the step for each generating unit is not flat but curved, depending upon the loading blocks and heat rate curve. Fortunately it is sufficient to know that the marginal cost is monotonic, so that higher load implies higher marginal cost (otherwise units would be dispatched out of their correct loading order). This means that the problem is reduced to shifting wind or PV generation from hours with low system load to hours of high system load.

Formulating this type of optimization problem is usually a straightforward application of linear programming, and is often framed as a network transportation problem where the goal is to minimize the cost of transferring a product (in this case, energy) between nodes (or time periods) across paths that have limited capacity (storage or inverter generation capacity in the present case). One thesis by Daryanian[24] has explored this formulation for the related case where customers or generators wish to optimize their production or generation schedules based on forecast electricity spot prices. This thesis develops an algorithm with two nested iterative loops for swapping energy between cheap and expensive hours which solves this restricted problem faster than the simplex method. The problem described in this prior thesis differs from the present one in that the product out or fuel in is shipped or arrives in a steady flow and the utility grid is an infinite source or sink for the electricity consumed or generated, whereas the NDT resources in the present case are not only limited but variable. This difference is not fundamental and requires only minor changes in the algorithm to accommodate it.

Unfortunately, the present problem was found unsuitable for a linear programming formulation for two reasons. The first reason is that the LP formulation is based on a known schedule or forecast of spot prices, while the current problem has as its basis an hourly forecast of system loads. As mentioned above, the transformation from system load to spot price is complex and non-linear. The problem can be solved by using a system marginal cost curve or an hourly simulation model to convert load to spot price data, but since the relationship is monotonic it was deemed simpler to optimize using the NEPOOL load data. The second and determining reason that linear programming could not be used is that the net NEPOOL hourly loads, and hence spot prices, are not *fixed*. This is not based upon the probabilistic uncertainty associated with forecast load, but rather upon that fact that net system load is changed as a result of the optimization itself (which is of course the goal). In order to make the benefits of different levels of dispatchability apparent for the PV and wind resources, a relatively large generation capacity was postulated (1000 MW). This is enough that the relative rank of net load and spot price for some hours can be shifted. It was for this reason that a new and original optimization algorithm was developed and implemented. The flow chart for the final algorithm is shown below in Figure 4.8.

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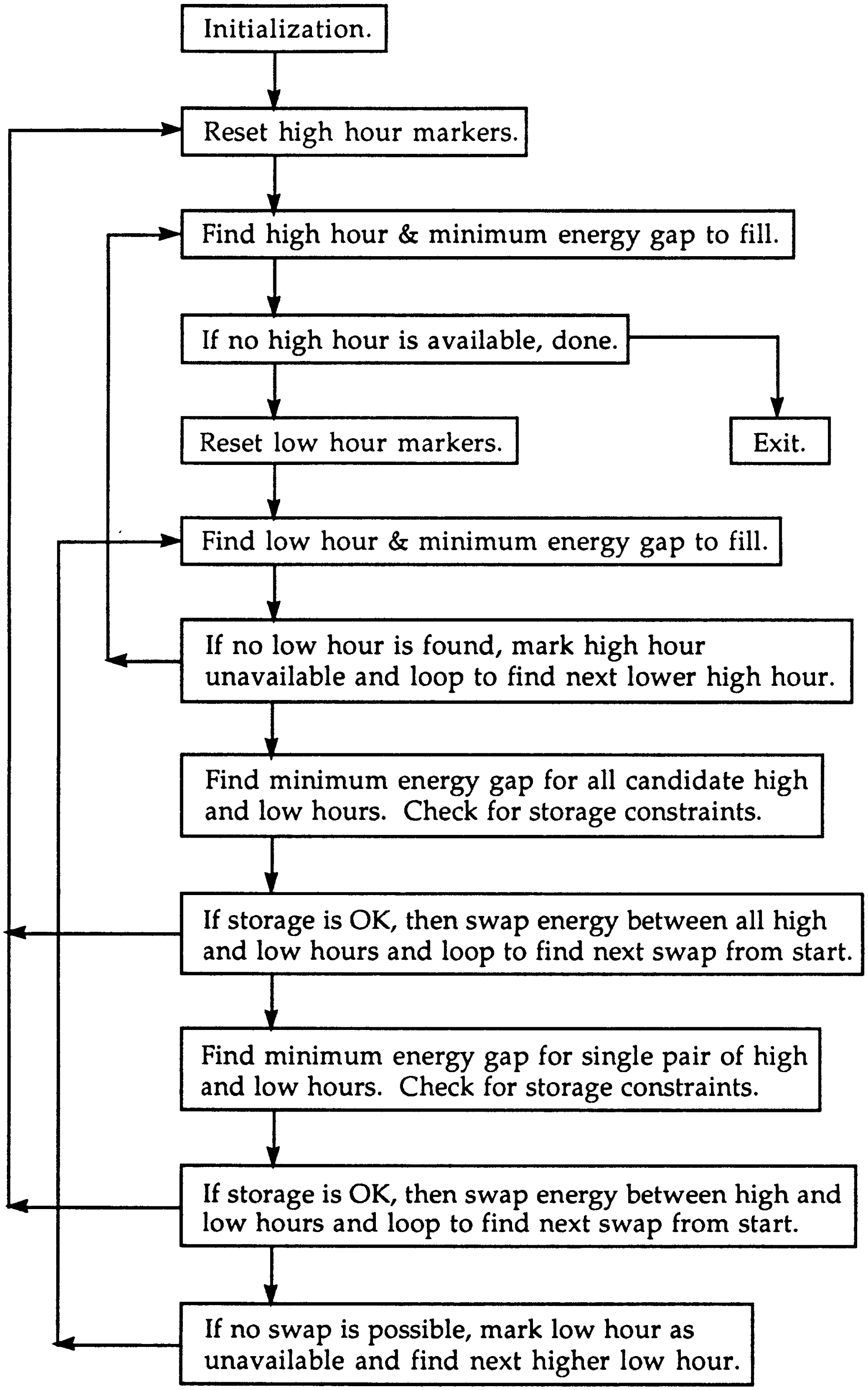
[24] Daryanian, B., *The Definition and Application of an Optimal Response Algorithm for Electricity Consumers and Small Power Producers Subject to Spot Prices*, S.M. Thesis, Technology and Policy Program, Mechanical Engineering Department, MIT, 1986.

Figure 4.8 - Flowchart for Storage Optimization



The full text of the complete FORTRAN program that implements this algorithm is attached as Appendix I of this thesis. This code is well commented to supply a detailed description of the algorithm in addition to the general discussion below following the flow chart.

The first step in the algorithm is initialization, which includes reading data, calculating and initializing variables, calculating hourly NDT generation from the hourly NDT resource data (insolation and wind speed), and generation of an initial solution. The initial solution essentially ignores storage, so that NDT generation (minus losses) equals energy into storage equals energy out of storage. Separate variables for energy in and out of storage rather than a single plus or minus variable was used so that NDT generation in excess of inverter capacity can be dumped when storage is already full.

The basic algorithm is similar to that of Daryanian, in that it consists of two nested searches to match high and low net load hours and to swap energy between them based on storage constraints. The high hour is found first, and the low hour found next. If storage allows, energy is swapped. If not, the low hour is marked unavailable and the next best low hour is found. If no more low hours are available or the high hour generation is exhausted, the next high hour is found. When all feasible swaps have been exhausted, the optimization is complete.

Beyond this basic similarity, several very significant differences exist. The objective of producing power at hours with peak net loads and spot prices means that as far as possible all peak hours will be flattened to the same net load. Likewise, the cheapest way of charging storage from generation will occur at the lowest hours and will tend to flatten the net load across the lowest hours. Because of this flattening effect, there may be several hours with the same high or low net load, each with a different amount of energy available for a swap. Because of this the high and low hour search sweeps not only mark the available highest and lowest net load hours, but also find the minimum energy available to swap (which is also the maximum energy that *all* candidate hours can swap). This amount of energy is called the "gap" in the flowchart above and in the program documentation. To speed up the process, the program attempts to swap energy between all the high and low hours identified if storage constraints remain unviolated. If storage constraints are binding, then energy is only swapped between a single pair of high and low hours and the amount of energy swapped may be reduced to just meet the constraints.

On top of this basic algorithm, several refinements were added. To improve total run times over the entire year, the planning period was made of variable length and exogenously specified. Periods which were an even number of weeks caused the first period to be adjusted so that successive periods ran from Sunday to Saturday. Periods which are not even weeks lead to problems with weekend/weekday storage optimization, since successive periods cover different days of the week. To meet this problem and reduce calculation times, planning periods were overlapped by 24 hours, so that the last day planned was appended to the leading edge of the next planning period. During the course of model development, planning periods of 2 to 4 days appeared to be the best balance between speed and reducing the amount of total period overlap. This seemed appropriate since this period is about the same length as medium range weather forecasts used to forecast both renewable generation and system load. The forecast resource and system load data used were assumed to be certain for the purposes of optimization. There seems little advantage to significantly longer planning periods given the forecast horizon and the largely diurnal variation in the resource patterns, but it would be possible to add uncertainty into the algorithm and have increases throughout the planning period. Finally, although only the year 1995 was optimized, the model allows for a variable number of years to be optimized, including exogenous input of a trajectory for NDT generation capacity over time.

It is not the purpose of this thesis to present mathematical proofs of optimality, but this algorithm can claim to produce optimal storage allocation because, 1) the algorithm selects possible swaps in order of attractiveness, and 2) it checks all combinations of hours for possible swaps and 3) it stops only when available energy to swap is exhausted or the storage constraints become binding.

The speed of the algorithm was not compared to other methods of solution, but its dependence upon problem size can be judged from the iterative nature of the nested search loops shown in the flow chart. Finding the high and low value candidate hours both involve sweeping through the entire planning period, which means that the calculation time is theoretically on the order of n squared, or $O(n^2)$, where n is the period length. This means that as the planning period doubles in length, the calculation time would quadruple. The energy constraint check also involves a sweep through the entire period, but is only done once for each proposed energy swap so it does not increase the overall order of the calculation. Obviously increasing the planning period length decreases the number of planning periods required per year (by a factor of n), so the overall order of calculation is O(n). However for the short planning periods used in testing and running the optimization model, the calculation increase required by the period overlap of one day added to each planning period was significant, so the net order was judged to be approximately $O(n^{1.5})$. For the final year long optimization runs which were performed, a planning period of two days was used. The average calculation time using a MicroVAX 3400. was 23.19 CPU minutes for each PV optimization run, and 35.85 CPU minutes for each wind optimization run. The wind runs take an average 55% longer to optimize because of their greater resource variability and the increased complexity of having generation available at night.

Figures 4.9 through 4.12 show how this algorithm behaves for photovoltaic generation with 40% storage capacity and 50% inverter capacity. The first weeks in January and July 1995 were modeled and the two days of January 7 (a Saturday) and July 2 (a Sunday) were chosen to illustrate the model's performance because they were representative, relatively easy to understand, and no storage was carried between days.

Figure 4.9 - NEPOOL Hourly System Load for January 7, 1995, With and Without Optimized Storage

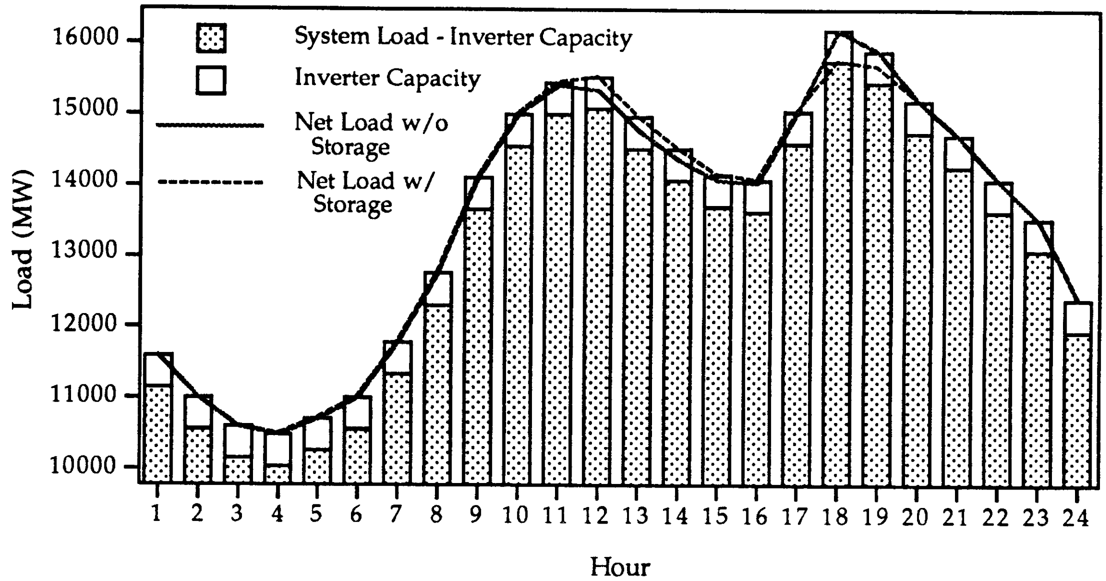


Figure 4.10 - Hourly Energy Flows and Cumulative Storage for January 7, 1995

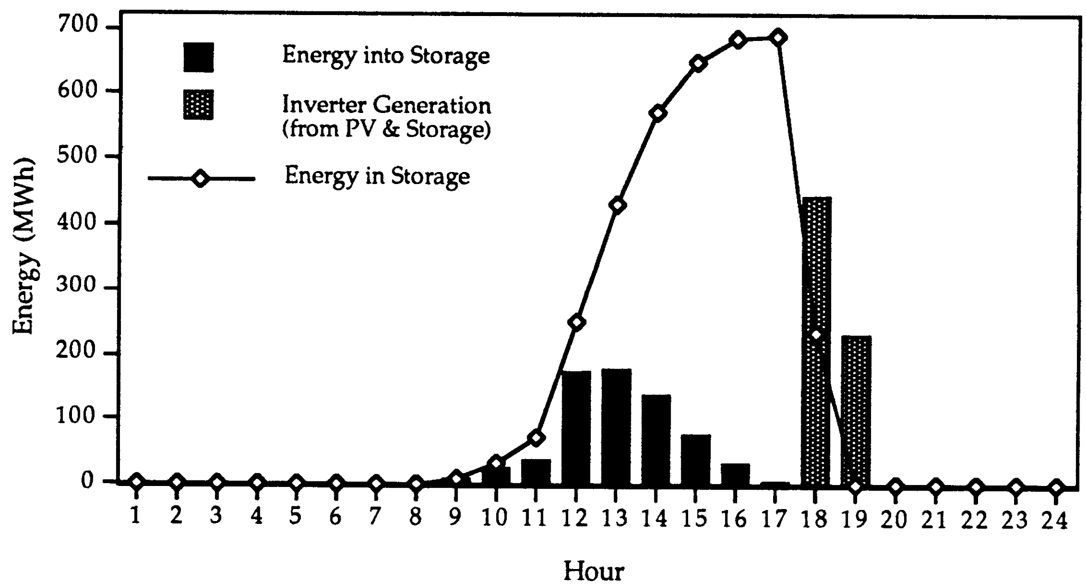


Figure 4.11- NEPOOL Hourly System Load for July 2, 1995, With and Without Optimized Storage

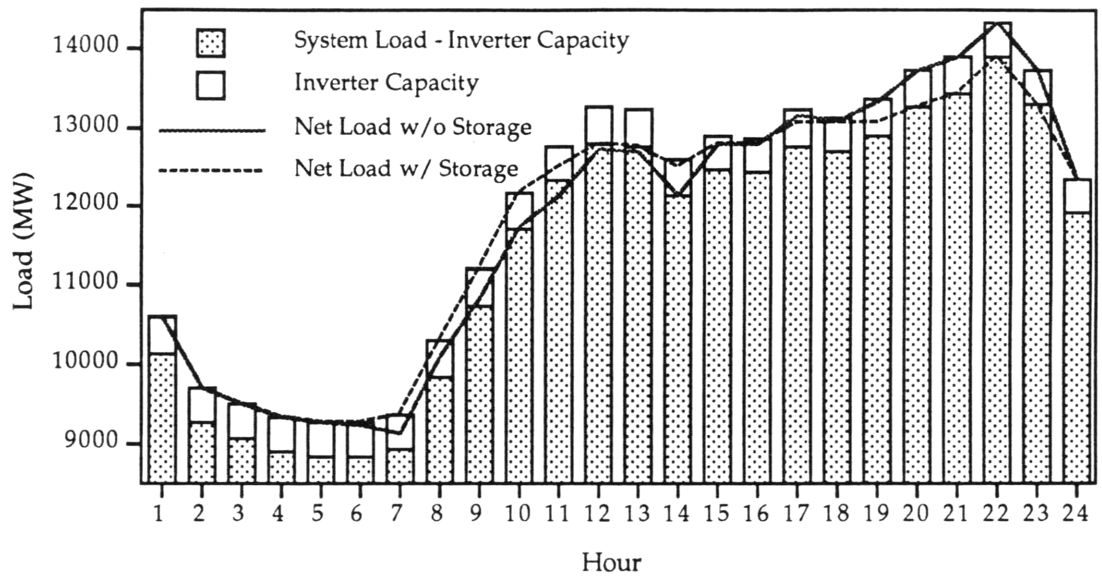


Figure 4.12 - Hourly Energy Flows and Cumulative Storage for July 2, 1995

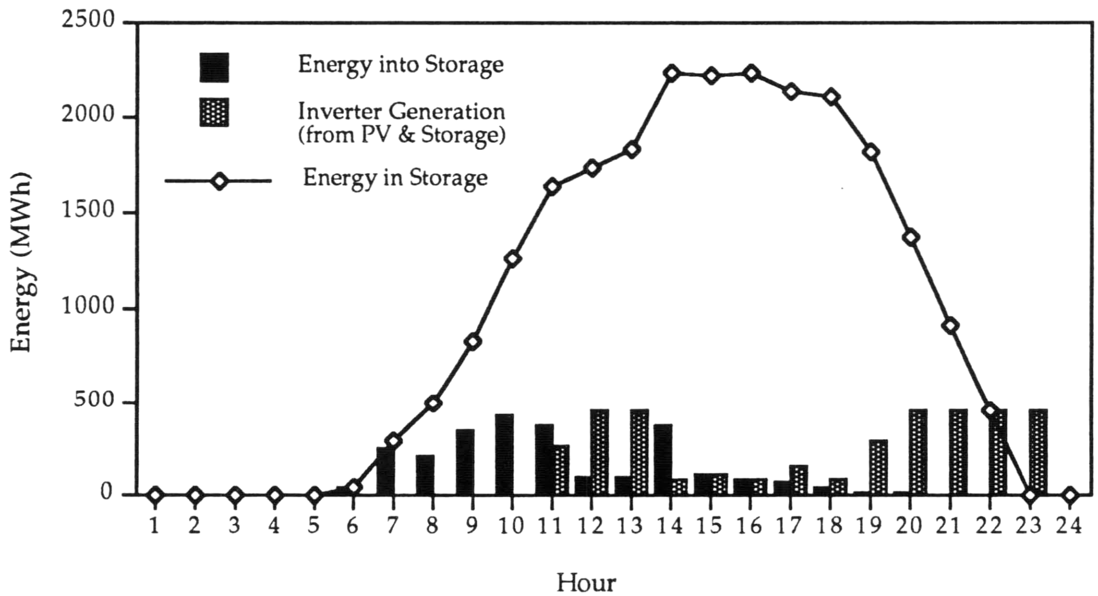


Figure 4.9 and 4.11 show the original NEPOOL system load without PV generation by the total height of the bar graph columns, while the white block at the top of the column shows the total amount of inverter capacity available (in this case 50% of PV capacity minus site losses, or 446 MW). This band of

white blocks in successive hours shows the range of net loads possible using storage. The lines superimposed over the column graphs show the system net load with PV generation added, both before and after the optimized addition of storage and inverter capacity, and both lines must lie within the white box at the top of each column. When the dotted line is above the solid line energy is stored, and when they are reversed energy is generated from storage. Figures 4.10 and 4.12 show more directly 1) the energy flow into storage, 2) the inverter generation from storage or directly from PV generation, and 3) the cumulative energy in storage.

These figures show that in January the brief hours of PV generation are stored and used to reduce the peak load in only two hours, while in July both PV generation and generation from storage are spread over more hours. Due to the way that the variables are defined, inverter generation may come either from storage or directly from the PV generation. For the July example generation is high enough in hours 12 and 13 that even after inverter generation is at the maximum there is still energy available to add to storage.

The storage and inverter capacity parameters were varied for both the wind and PV cases as shown in Table 4.9 below. As described above, the storage parameter is a fraction of the maximum day's generation for the year, and the inverter parameter is the fraction of NDT generation capacity net of site losses. Storage optimization and valuation were done for each technology for all combinations of these storage and inverter capacity parameters, so that a total of 84 runs in all were performed.

Table 4.9 - Storage and Inverter Capacity Parameter Ranges

Parameter	Range (%)						
Storage Capacity	0	10	20	40	60	80	100
Inverter Capacity	25	50	75	100	150	200	

The optimization algorithm was also used to keep track of the top ten peak loads before and after optimized storage was added. This load reduction can be used to figure the capacity credit for NDT resource generation, and depends only upon inverter capacity once a minimum amount of storage capacity has been reached. Table 4.10 below shows before and after results for the single peak hour and the average of the top ten peak load hours as a function of the amount of inverter capacity used for both the wind and PV generation.

Table 4.10 - Annual Peak Load Before and After Storage

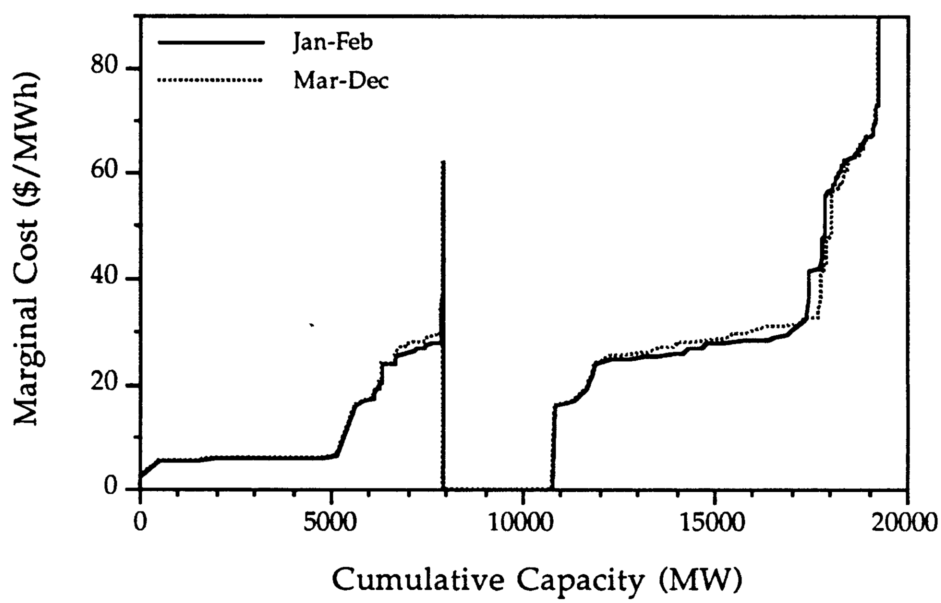
Technology	Inverter Capacity (%)	Inverter Capacity (MW)	With Storage Peak (MW)	With Storage Average (MW)	Without Storage Peak (MW)	Without Storage Average (MW)
PV	25	227	223	216	223	223
PV	50	455	446	397	446	446
PV	75	682	466	445	668	668
PV	100	909	466	445	891	793
PV	150	1364	466	445	1015	853
PV	200	1818	466	445	1027	871
WIND	25	217	21	46	180	147
WIND	50	435	21	46	277	224
WIND	75	652	21	46	277	235
WIND	100	870	21	46	277	235
WIND	150	1304	21	46	277	235
WIND	200	1739	21	46	277	235

Once the 1995 hourly net load files were generated, they were converted to EGEAS input files containing load duration curve information, using an EGEAS preprocessor. EGEAS model runs were then performed for the year 1995 using the AGREA EGEAS database discussed in previous sections. The hourly net load files obtained could have been used directly as input for the Polaris model, and the hour by hour model might have given slightly better results for the storage optimization. However given the need for many runs, the greater difficulty in using Polaris at NEES rather than EGEAS at MIT, and the need to limit the burden on NEES's generosity in performing these runs, whatever analysis could be done using a load duration curve model was performed on EGEAS at MIT.

The results of the EGEAS runs were inconclusive, with almost no difference in results between the runs, apparently for two reasons. First, the EGEAS model results were given in units of millions of dollars to the nearest tenth. Second, using the EGEAS model means that the energy value of NDT generation was not given directly, so that only the differences in value between the different cases can be obtained by the delta in total system operating costs. The benefits of simply shifting energy from low value hours to high value hours for a 1000 MWe PV or wind plant with their relatively low capacity factors were not enough to show up as significant differences with the EGEAS output as set.

Instead, a different approach was taken to obtain more precise results. As noted above, the marginal cost of each additional MW of load depends upon its point in the loading order, and the savings due storage are the product of the energy shifted times the marginal cost difference between the hours when energy goes in and comes out of storage. The marginal cost supply curve for the NEPOOL system is shown below in Figure 4.13.

Figure 4.13 - NEPOOL Marginal Cost Supply Curve



The most obvious thing about this figure that it is not monotonic, but instead split into two monotonic segments. The capacity shown 0 to approximately 8000 MW does actually have the dispatch cost shown, but is designated as "must-run" capacity for various reasons in the AGREA EGEAS database used. The largest amount of this must-run capacity is the first 5000 MW of capacity which is nuclear and costs 5 to 6 $/MWh. Most non-utility generators are also designated as must-run units. In reality, the NEPOOL system load does not drop below 6934 MW in 1995, so that most of this capacity does run all the time. For analytic purposes any unit that is must-run has a marginal cost of zero. Above the must-run capacity in the dispatch order is approximately 3000 MW of hydropower capacity with a zero dispatch cost, followed by coal, natural gas, and oil fired capacity in ascending order.

The second thing of interest in this figure is that there are two marginal cost supply curves, one for January through February and one for March through December. The reason is that during these two winter months, 3450 MW of capacity in the AGREA EGEAS database are subject to fuel switching from natural gas to fuel oil. This changes the unit dispatch order, but as can be seen the difference is not dramatic since the curves for both periods are approximately parallel.

The last, least obvious, and most important thing about Figure 4.13 is that the approximately 27.5 GW of NEPOOL capacity have been derated on the x axis to less than 20 GW for several reasons. All units require maintenance and are subject to forced outages, and many units have energy limited generation due to contractual, fuel supply, or other reasons. Since units are not withdrawn from the dispatch order in this method of analysis, it is necessary to derate the individual unit capacities for these factors. In the AGREA EGEAS database the forced outage rate was increased to include maintenance requirements, while maintenance scheduling was used for fuel switching purposes, so both these factors could be included by derating unit capacities by their forced outage rate. Likewise, if a unit had an energy limit the capacity was reduced so that at full output for the year the required energy would be reduced.

Applying both of these deratings reduced capacity by too much, so they were each applied singly to unit capacity for all must run units, and the minimum capacity was chosen. This method was necessary to keep total must run capacity below the minimum system load and also have enough total capacity for peak system load. It makes sense because the dispatchable units are not energy limited (except for hydro) and are more able to schedule maintenance.

Finally, the unit capacities in MW must also be derated by the NEPOOL average T&D losses of 7.2% in order to be on the same basis as the MW of hourly net load produced by the storage optimization model. After derating unit capacities for all these factors, total cumulative NEPOOL capacity was reduced to 19,296 MW, which was exceeded by system load for 36 hours out of the year modeled. This indicates that the way in which units were derated may yield costs which are slightly higher than given by an LDC or hourly model which handles the derating factors more realistically.

Once the marginal cost supply curve had been obtained, the storage optimization algorithm was modified to sum the total value of inverter generation based on the marginal cost of each hourly net load for the year. Additional modifications were also added to track NDT generation, energy storage and inverter generation, and NEPOOL system load before and after NDT generation for the annual peak hour and the average of the annual top ten hours.

The results of the optimized PV and wind storage across the range of storage and inverter capacities described above are presented and discussed in Section 5.3 of Chapter 5.

4.4 Spinning Reserve

As discussed in Chapter 3, spinning reserve is required for reliability of customer service, and any utility option permitting the spinning reserve to be reduced deserves a benefit or credit for this reduction.

Analysis of spinning reserve requires an hourly model because system load changes hour to hour and this sequential information is lost in a load duration curve model. In addition, hourly models contain more detail about unit loading blocks and constraints on unit dispatch due to minimum down times and run times, both of which are needed to correctly calculate spinning reserve. EGEAS requires an input for the spinning reserve level, and it was initially hoped to vary spinning reserve on both models as a means of cross calibrating the models. However, using EGEAS for this purpose requires loading block data that is not presently in the current EGEAS database, so all results were obtained from the Polaris model. Since spinning reserve is a system level operating parameter, no other additions or changes were required to be made to the base Polaris database described above.

The level of spinning reserve may be defined or specified in several ways, and the operating level required may vary depending upon the source of the standard. Spinning reserve needed depends upon the size of the system, and in particular upon the size of the single largest unit which may fail unexpectedly. For this reason, the spinning reserve requirement is generally stated as some percentage of the capacity of the single largest unit in operation. It may also be stated as a percentage of the total capacity of the two largest units in operation. In practice these definitions are not much different, because the largest baseload units in NEPOOL are nuclear plants which are similar in size. The Polaris model allows spinning reserve to be defined in three ways; 1) as a constant MW amount 2) as a fraction of hourly busbar load, and 3) as a percentage of the largest unit in operation, but only the first measure was used in the work performed.

Spinning reserve standards are set regionally by each power pool which has common dispatch. The North American Electric Reliability Council (NERC) has nine regional council which set individual standards (usually in total MW) for 10 and 30 minute response categories. The 10 minute response category is called reliability reserve and subdivided into spinning reserve and non-spinning reserve (which includes interruptible load and units which can respond within 10 minutes without spinning standby), and the 30 minute response reserve is called supplemental operating reserve.

For New England, the standard of operating reserve required by NEPOOL Operating Procedure No. 8 (OP-8)[25] is 100% of the single largest contingency loss (generally the largest generating unit in operation) which is synchronous reserve available in 10 minutes, plus 50% of the second largest contingency loss which is asynchronous reserve available in 30 minutes. However, when Polaris is actually used for NEPOOL final dispatch with little or no alteration by the dispatchers, a much lower spinning reserve level of

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25 NEPLAN Staff and the NEPOOL Generation Task Force, *Summary of the Generation Task Force Long-Range Study Assumptions*, p. 4, August 1993.

approximately 50% of the single largest contingency loss is used, based upon the standard given by the NERC. For some short periods an even lower level is sometimes used, and for the purposes of planning studies a minimum standard of at least 200 MW of operating reserve is assumed.

The difference between 10 and 30 minute reserve capacity is of course blurred when using an hourly model, because smaller time increments cannot be distinguished. In this case, spinning reserve is a marginal increment of capacity above the hourly system load operating at the lowest loading block. For this analysis, the spinning reserve parameter was varied from 0% to 200% in 10% increments. The extreme ends of this range are understood to be unrealistic, but were included to observe their effects.

The purpose of spinning reserve is to reduce generation-based outages, and Polaris has an input parameter which determines how closely it adheres to the standard supplied. The first option ("degrade") allows a limited amount of flexibility so that the model may drop below the standard for very short periods due to unit operating constraints. The second option ('shed") is stricter, and produces a larger cost for unserved energy. The stricter choice was used in the present analysis so that the maximum effect of varying spinning reserve on total variable cost could be observed. The Polaris database cost/MWh for unserved energy was quite high, but the cost set on unserved energy is often arbitrary and lacking any real economic basis. These results which are presented and discussed in Section 5.4 of Chapter 5 exclude the costs of any possible unserved energy, and instead focus on the balance between variable operating costs and capital recovery costs.

4.5 Dispatchability for Thermal Units

Unlike the non-dispatchable wind and solar resources discussed in section 4.3 above, more conventional thermal units can be directly controlled. They are dispatched following their variable cost in the loading order which is at the heart of power system operation, modeling and planning. This dispatch is constrained however by physical and operational limitations. This section describes the source and definition of these constraints, the choice of generic plants used to illustrate them, and the choice and range of parameters which were varied in this analysis.

The most obvious and physical bases for dispatch constraints are the thermal mass of a generating unit and the thermal stresses involved in cycling them on and off. Simply put, it takes a long time for a big generating unit to warm up or cool down and turning it on too rapidly can cause damage and increase maintenance costs. These limitations are obviously linked to size. Large baseload units require longer to respond, while small peaking units are built for fast response times. For the purposes of description and analysis, dispatch constraints are separated and defined using several different measures. These include the following.

- Minimum Run Time - The minimum time a unit can be operated before it can be shut off.
- Minimum Down Time - The minimum time a unit must be shut off before it can be restarted.
- Hot to Cold Start Time - The time it takes for a unit to cool down so that a startup incurs the higher cost of a cold startup instead of a hot startup.
- Ramping Time - The time it takes for a unit to increase from zero to full capacity generation.

These measures are somewhat interrelated, and not every source or model uses all of them or necessarily agrees upon their exact definition. The current version of the Polaris model uses only the first three, implicitly assuming that units can be turned on immediately without ramping up.

Typical values of these constraint measures are given for different size units with different technologies and fuels by the Generation Task Force (GTF) Assumptions Book[26], although they are somewhat conspicuously missing from the Electric Power Research Institute Technology Assessment Guide (EPRI TAG) which describes generic technologies for more strategic

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[26] NEPLAN Staff and the NEPOOL Generation Task Force, *Summary of the Generation Task Force Long Range Study Assumptions*, Exhibits 27 and 28, August 1993.

purposes that are generally modeled by load duration curve production cost models.

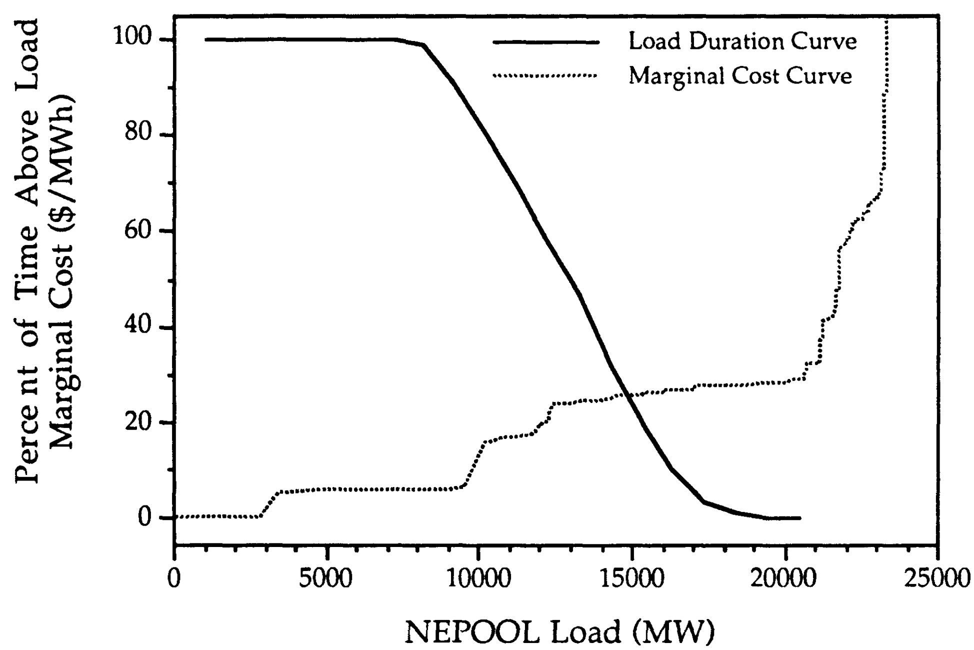
At the start of this analysis it was believed that these dispatch constraints were based primarily, if not solely, upon the physical grounds stated above. However, in conversation with NEES personnel it was learned that the minimum time constraints are also based on other factors, including maintenance costs, emissions, and how the plant may be dispatched. It is more correct to view the definition of dispatch constraints as a scale or spectrum, where the minimum limits of operation may be based on physics, but normal limits are based on a decreasing scale of maintenance costs and emissions.

These operating limits are apparently supplied to dispatchers by plant personnel, but the impacts of unit dispatch back upon plant generation and total system cost are not considered (or known). The present analysis is aimed at remedying this lack, so that plant dispatch constraints can be reach by balancing plant v. system costs. It should be noted that under deregulation, the market value of each plant is based upon the net present value of future revenues and costs. When revenues are attributed to individual plants based on their generation rather than to the utility as a whole, the operating constraints may have a significant impact, and the system operator or coordinator will need to supply correct pricing signals to ensure minimum total system cost.

It was expected a priori that the cost of dispatch constraints (and the benefit of relaxing them) is not equal across the loading order. Although baseload plants have the tightest constraints (i.e. the longest minimum times), they are turned on and off so infrequently that the value of faster operation was expected to be small. Peaking units at the other end of the loading order have such fast response times that no further benefit can be expected. It was therefore expected that the greatest benefit of faster response would be found for intermediate units.

To illustrate this range of values it was necessary to select a number of generic generators with a range of variable dispatch costs and representative fuels. Figure 4.14 below shows the distribution of dispatch cost against the cumulative utility owned capacity of the NEPOOL region, based on the AGREA EGEAS database. Unlike Figure 4.13 above, must-run and dispatchable units have not been separated nor unit capacities derated. This figure also gives the 1995 NEPOOL load duration curve, showing the percentage of hours above a given load level. This figure correctly shows that peak load is approximately 20.5 GW, and that generation capacity is larger by the reserve margin, but the peaking units shown beyond the end of the load duration curve are still used during planned and forced outages since the unit capacities are not derated.

Figure 4.14 - NEPOOL Load Duration
and Marginal Cost Supply Curves



Representative plants were chosen at five evenly spaced points along this curve, with a range of fuels. As far as possible, larger plants at each cost point were chosen so that the impacts upon total system cost would be more discernible.

As noted above, the Polaris model includes three constraints; minimum run time, minimum down time, and the hot to cold startup time. Based on the Polaris manual, the hot to cold startup time does not affect dispatch, but only changes the startup cost incurred each time a unit begins operation. Because of the need to limit the number of runs, it was chosen to concentrate upon the minimum run and down time constraints as parameters for variation in the study. Typical values for these parameters were obtained from three sources, including the GTF Assumptions Book, the NEPOOL database examined on site at NEES, and consultation with NEES personnel[27]. Based on these references, typical base values for the minimum run and down time parameters were chosen for each of the five plants selected according to their dispatch cost. These parameters were varied above and below the base values, with larger variations for base load plants with slower response times and smaller variations for plants with faster response times. These parameter variations were combined by combining all minimum run times with the base minimum down time and vice versa for each unit. This yielded a total of 50 cases to be analyzed by Polaris runs, which are shown in Table 4.11 below with the base parameters shown in bold.

Table 4.11 - Unit Dispatch Constraint Variations

Unit 1		Unit 2		Unit 3		Unit 4		Unit 5	
Min. Down	Min. Run	Min. Down	Min. Run	Min. Down	Min. Run	Min. Down	Min. Run	Min. Down	Min. Run
6	4	4	2	4	2	1	1	**0**	0
12	8	8	4	8	4	2	2	1	**1**
24	**12**	**12**	**6**	**12**	**6**	**4**	**4**	2	2
36	18	18	8	18	8	6	6	4	4
48	24	24	12	24	12	8	8	6	6

(Note: All times in hours)

Having selected from the AGREA EGEAS database the five generic units listed above, and the parameter variations to apply to them in the modeling analysis, it was then necessary to make the appropriate changes to the Polaris database. The first possibility was to create new generic units and add them to the existing Polaris database, replicating similar existing units and changing the total NEPOOL capacity. Instead, an existing unit was chosen, removed from the existing database, and replaced with a similar generic unit. The generic units had the same fuel and heat rates, but capacities were changed so that results would be representative of the

27 E-mail correspondence from Mr. Tom Mikulis, Thermal Administrator, New England Electric System, 8 January 1996.

NEPOOL system but not exact. This replacement of existing units by generic ones was done for two reasons. First, it was easier to do, since it was not necessary to modify the Polaris database in every detail for the new plants. Second, and more importantly, it was deemed more realistic to change system size by modifying the size of an existing plant rather than by adding an entirely new one. The existing plants were replaced by the generic ones singly for analysis, rather than replacing all five and then varying the parameters for only one at a time. This choice was a tradeoff between accuracy in results for each single unit v. the comparability of results between units, and it seemed that the former was to be preferred. As required by the confidentiality agreement signed with NEPOOL, the identities of the units selected for generic replacement are not revealed in this work.

Although Polaris does dispatch units based on the constraints described above, its algorithm has some shortcomings which were discussed with Decision Focus, Inc. (the authors of Polaris) and which should be mentioned. As system load changes Polaris follows the loading order, starting or stopping plants as required. This is first done without consideration of the dispatch constraints. This initial dispatch is then checked for violations of the dispatch constraints. If a unit violates the minimum run time, it is kept running longer. If a unit violates the minimum down time, it is kept running through the down time period. The dispatch is then feasible, and is checked for optimality. If it is cheaper to keep a unit running, rather than shut it down and then incur the startup cost later, it is kept running through the feasible shutdown.

The difficulty with this algorithm is that the only option considered for both feasibility and optimization is to keep units running longer. However, it is easy to postulate a situation where it would be more economical for a unit not to run at all, but to instead be replaced by a unit further up the loading order which would run for a shorter time or have a lower startup cost. In addition, ramping times are not considered (at least separately from minimum run times), and the ramping profile is an on/off step function for each loading block.

Decision Focus recognizes these issues, and is addressing them in a new model upgrade that was scheduled to be released in March, 1996. This thesis was not delayed for this release, not only because of the uncertain release date, but more importantly because the additional detail of the new release will require new operating data to be collected for each existing plant which will require a significant amount of time for NEPOOL to gather. However, the fact that Decision Focus is updating the model to improve its handling of these issues illustrates the important role which dispatch constraints can play. Because any improvement in the algorithm will bring its results closer to optimality, the results of the analysis described above can be considered conservative minimum estimates of the benefits due to relaxing dispatch constraints.

This chapter has described the basis and methods of analysis for the five sample component values chosen in Sections 3.1 through 3.5. This includes the ranges of parameter variation, database assumptions, and the choice and development of the models used. The results of the component value analyses described in this chapter are presented and discussed in the same order in Sections 5.1 through 5.5 of the following chapter.

5.0 Results for Component Values Analyzed

This thesis proposes that there are sources of value which are not included in conventional average or levelized cost methodology. These sources of value are becoming increasingly important to those who generate, transmit and consume electricity as the competitive deregulation of the market continues. Chapter 2 develops the theoretical framework of how utility options and individual component values are related, while chapters 3 and 4 discuss individual values, identify the subset of values chosen for analysis, and lay out the methodology and assumptions used for their evaluation.

This chapter describes the results for the five sample component values chosen to demonstrate the theory developed (% reserve margin, unit size, resource dispatchability, % spinning reserve, and thermal unit dispatch constraints). Component value supply curves have been obtained by sensitivity analysis, varying one or two parameters in the set of option characteristics. These supply curves can be used to value utility options which possess the component value in question, regardless of the option technology. These value supply curves can also be used to choose the optimum level for each option by comparing them with the cost curve for the option in question. This chapter also reduces component values to a common \$/kW or \$/MWh basis so that they can be compared with each other and to conventional option costs to show which are most significant. The five component values chosen to demonstrate the new economic methodology developed are not necessarily the largest available, and other component values described in Chapter 3 (such as T&D values) appear capable of being equally as significant, if not more so.

In four of the five cases evaluated, the results presented in this chapter are based on analysis of the New England system over a single year study period, because only a single year's modeling was necessary to demonstrate them. However the benefits of different utility options will endure for different lengths of time, depending upon the set of key characteristics upon which they depend. Some characteristics (e.g. system composition and the variable cost supply curve) are slow to change due to the sheer inertia of the capital investment in the existing utility system, while others (such as dispatch rules) may be switched on and off.

In order to compare benefits that have different duration's, it is necessary to set a common time basis. One way of doing this is to assume that all value benefits will have a common life span, and use a net present value factor to discount the future benefits. For example conventional utility options (new generating plants) have life times that range from 20 to 40 years, although these are often more tied to financial than technological reasons. For this thesis, the primary common time basis was set to be the year 1995. For the one case with results over a 20 year period, the net present value was levelized to produce a 1995 annual value. Based upon the AGREA EGEAS data base, a nominal discount rate of 10% and an assumed long run inflation rate of 3.3% were used for these calculations. However, it may also be desirable to compare these annual results with the capital costs of conventional utility options. For this purpose only it was assumed that the benefits could be maintained for a life time of 30 years, which gives a net present benefit of 9.427 times the 1995 annual benefit.

Converting the results in this chapter to common units and time basis makes it possible to compare the relative scale of different component values, but some caution should be observed in transferring these values to other utility systems. The NEPOOL system is composed of a fuel and generation mix that is different from other regions of the country (particularly in the amount of oil burned), and so these component value supply curves will not transfer directly to other regions.

5.1 Reserve Margin

The major question in determining the value of system reserve margin is the balance between fixed capital recovery costs which decrease with reserve margin, and variable dispatch costs which increase as reserve margin decreases. For the NEPOOL system, this question was posed in two ways, as described in Chapter 4. The first way was by asking what if the existing system had been built, only smaller, by fractionally reducing the capacity of all units. The results for this case are shown below in Figures 5.1 and 5.2.

Figure 5.1 - Change in Total NEPOOL System Costs as a Function of Reserve Margin (%)

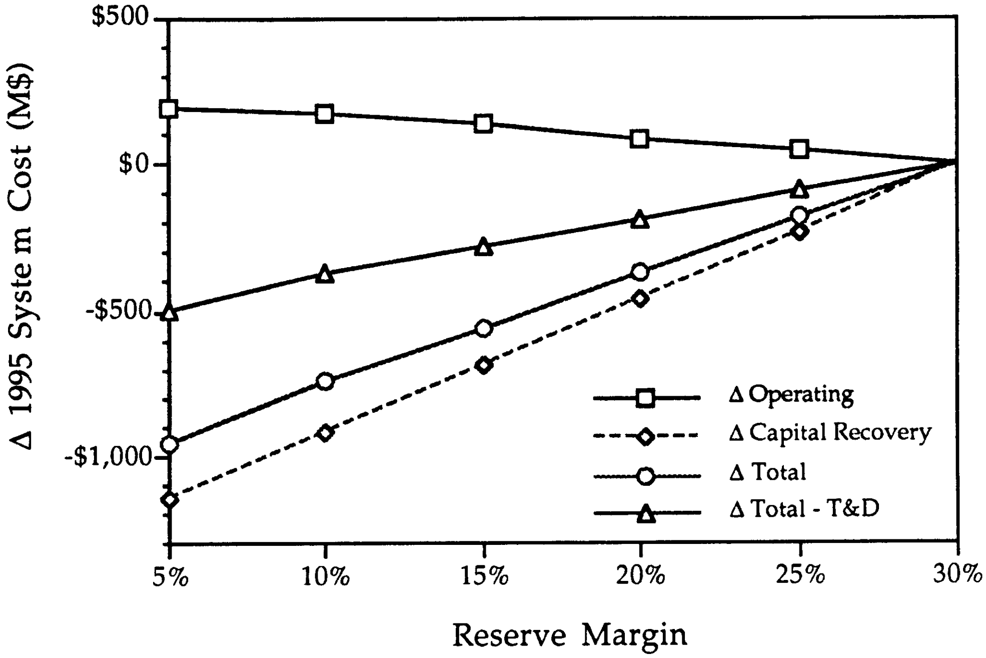
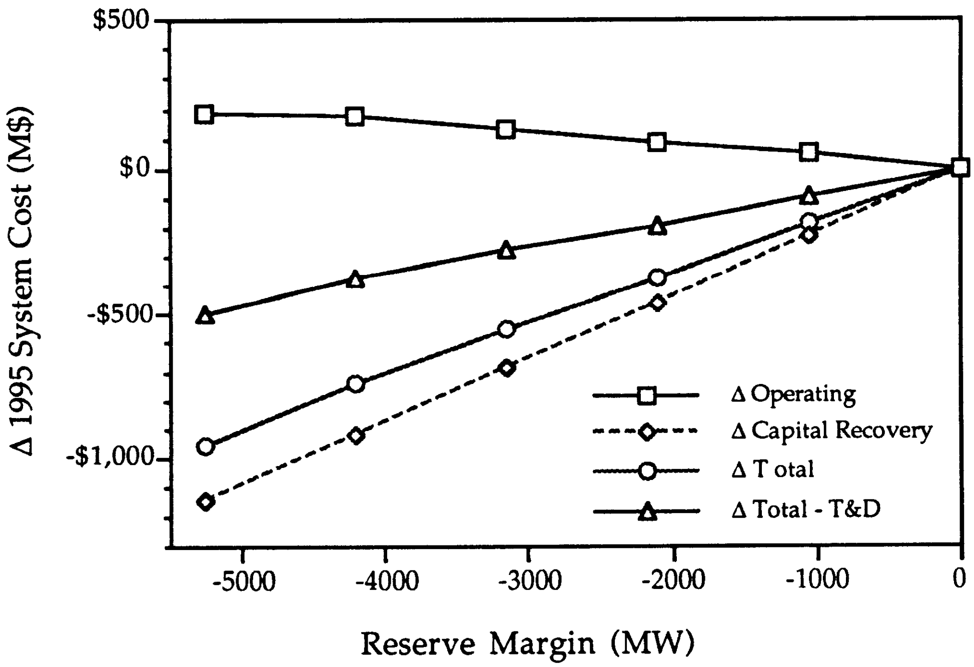


Figure 5.2 - Change in Total NEPOOL System Costs as a Function of Reserve Margin (MW)



These two figures show the same results in slightly different ways. Figure 5.1 shows the changes in total 1995 NEPOOL system costs as reserve margin decreases from 30% to 0%. As expected, the total variable system operating costs increase, but only slightly from $2726.9 to $2915.7 million as the reserve margin decreases from 30% to 5%, a net increase of $188.8 million or only 6.9%. This slight increase is dominated by the large decrease in revenue requirements necessary to recover the capital costs of the smaller system. The NEPOOL capital recovery requirement for generation, transmission and distribution plant is $6.063 billion for 1995 as described in Chapter 4, including NEPOOL's payments for non-utility generation and power purchases (NUGs and IPPs are 12% of total 26.5GW NEPOOL capacity). The decrease in reserve margin from 30% to 5% means that 1995 revenue requirements decrease proportionately from $5958 to $4812 million, or a decrease of $1146 million. The total system cost is of course the sum of the fixed and variable costs, and declines from $8685 to $7728 million. This decrease of $957 million is shown in Figure 5.1 above, next to and above the fixed cost line.

Although the capacity of each generating unit was reduced fractionally in this case, the amount of transmission and distribution capacity cannot be reduced because the system load remains the same, and hence the reduction of capital recovery costs above is overstated. As noted in Chapter 4, T&D is 40.5% of the national gross investment in existing electric utility plant for generation, transmission and distribution, so NEPOOL 1995 capital recovery requirements for generation plant only are $3.607 billion. The fourth line in Figure 5.1 above shows the total savings benefit due to the reduced reserve margin from 30% to 5% after T&D costs have been excluded. These total costs decrease from $6272 to $5779 million for a total savings of $493 million. As discussed in Chapter 4, the results for operating and total capital recovery costs are relatively certain, as they are based on historic system data, but the adjustment excluding T&D costs is less certain due to the uncertainty of applying an average national T&D fraction to New England capital recovery requirements.

The benefits of reducing transmission, and especially distribution, requirements are notoriously site dependent, and for this reason this very important component value was not evaluated as a generic example in this thesis. However, note that if DSM measures or distributed generation had been used in the past to reduce T&D investment by amounts proportional to generation capacity reductions in the present case, this would represent an average savings of 40.5%, and would have been worth $2.456 billion in 1995.

Figure 5.2 above shows the same information, but instead of giving reserve margin in percentages, it shows the change in NEPOOL reserve in absolute MW. This is more relevant when comparing NEPOOL results against another system. Because the impact of variable costs is so small compared to fixed costs, the fuel blend and unit efficiencies of a different system will not be very important compared to the capital cost of the existing plants in that system.

For the purpose of comparison with the other component value benefits presented in this chapter, the slope of these two graphs can be expressed in $/kW. The 25% reduction of reserve margin modeled (from 30% to 5%) represents 5106 MW for the NEPOOL system. Because the net benefits of reducing reserve margin are dominated by the linear reduction in capital cost requirements, it is reasonable to state the average benefit available is $493 million/5106 MW, or 96.6 $/kW. If DSM measures or distributed generation could have reduced T&D capital recovery costs by the same amount as the fractional capacity reductions in this present case, then this would be worth 90.9 $/kW for a total value of 187.5 $/kW.

As described in Chapter 4, the second reserve margin case is one where nuclear plants were successively eliminated (that is, hypothetically never built) in order of their age from oldest to youngest. This gives results for 8 different levels of reserve margin, from 32.3% (all nuclear plants in service) down to 5.1% (7 plants totaling 5556 MW not built). The newest plant (Seabrook) was always kept in service, because its elimination would have reduced reserve margin to -0.7%. The results for this case are shown below in Figure 5.3, and 5.4 below which again show the differences in 1995 NEPOOL system costs versus percent reserve margin and versus the decrease in NEPOOL reserve in absolute MW of capacity respectively.

Figure 5.3 - Change in Total NEPOOL System Costs as a Function of Nuclear Units Unbuilt (% RM)

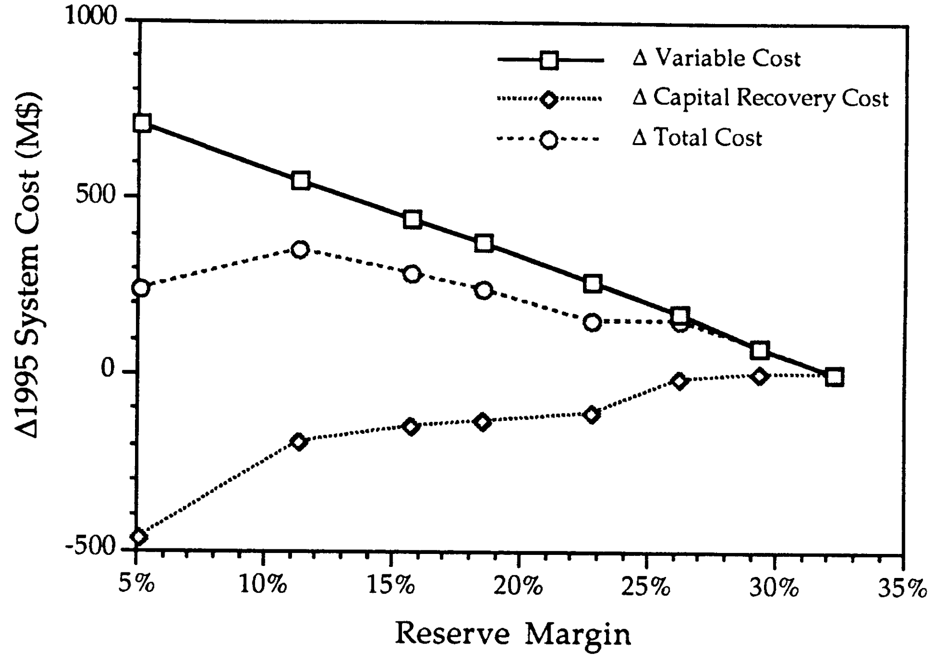
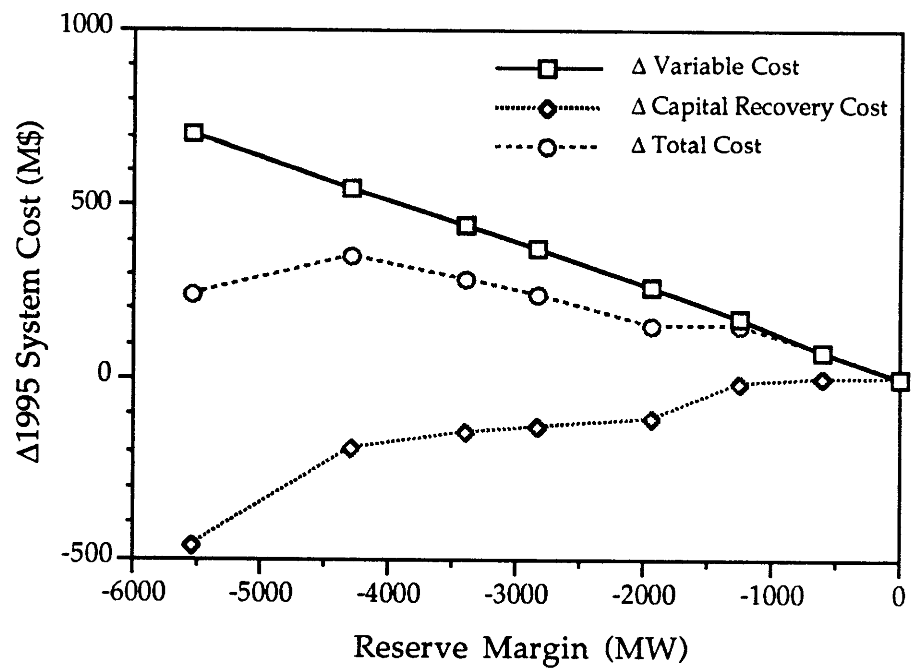


Figure 5.4 - Change in Total NEPOOL System Costs as a Function of Nuclear Units Unbuilt (MW)



As these figures show, the increase in total variable operating cost for the NEPOOL system is dramatically larger than in the first case, because nuclear power is approximately 20% of total capacity, and constitutes almost all the non-hydro base load capacity (minimum system load is 6934 MW and averages 7212 MW for the 10 lowest hours, while nuclear 'must-run' capacity totals 6753 MW and hydro totals 5745 MW, excluding pumped storage). As nuclear capacity is reduced, the system operating cost increases from $2707 million to $3410 million. This is a total increase of $703 million, or 20.1%. This cost represents the additional 1995 cost if these plants were retired now (as opposed to never built, as in the current case). These costs are based uponcribing the existing system so they are relatively quite certain.

In contrast, the future capital recovery requirements are significantly reduced, because nuclear plants are the most expensive base load capacity. As explained in Chapter 4, sunk costs prior to 1995 have been ignored, and the capital recovery requirements for these plants are based on their depreciated rate base values (or embedded costs) which are the remaining amounts which must be paid off. These embedded costs equal original unit cost minus cumulative depreciation, both of which are accounting numbers calculated in mixed year dollars. In order to compare these numbers with the 1995 variable costs, the embedded costs were converted to annual payments over the remaining life of each plant (assuming a full 40 year license life), using the nominal NEPOOL interest rate of 10%. As described in Chapter 4, a number of assumptions were made in deriving the embedded cost estimates so these results are slightly less certain than the operating cost results.

Combining the variable and capital recovery costs gives the total change in NEPOOL system costs due to the successive elimination of nuclear units. The overall trend of these results is in the opposite direction from the first fractional reduction reserve margin case. It shows that had existing units not been built, there would be a very significant total cost increase (or negative value) for all but two units.. For the Pilgrim unit the marginal variable cost increase and the decrease in depreciated capital cost (embedded cost) are approximately equal. The Millstone 3 unit was so expensive and is so relatively young that its remaining capital cost is greater than the increase in variable costs had it never been built. Table 5.1 below shows the 1995 capital recovery cost, variable cost, total cost and marginal value per kW for each plant's elimination. The total's line gives the sum of each column for all seven nuclear units, except for the final column where it gives the overall average value per kW.

Table 5.1 - Marginal Value of Removing NEPOOL Nuclear Units

Name of Plant	Capacity (MW)	Δ Cap. Cost (95 M$)	Δ Var. Cost (95 M$)	Δ Total Cost (95 M$)	Marg.Value (95 $/kW)
Connecticut Yankee	600	0	77	77.3	-128.8
Millstone 1	662	-19.7	93.9	74.2	-112.2
Pilgrim 1	678	-92.8	92.0	-0.8	1.2
Maine Yankee	890	-23.7	113.8	90.1	-101.2
Vermont Yankee	563	-18.6	62.8	44.2	-78.5
Millstone 2	910	-42.9	107.5	64.6	-71.0
Millstone 3	1253	-269.5	156.2	-113.3	90.4
Total	5556	-467.2	703.5	236.3	-42.5

The two reserve margin value cases considered above do indeed show that the value of reserve margin depends upon what type of system with lower reserve margin is compared to the present case. In the first case, the reduction in fixed costs dominates a slight increase variable costs, while in the second case the reverse is true. Of the two cases considered the first one seems most interesting, because it seems more indicative of how much could be saved in the future by reduced reserve margins since the structural inertia of system composition makes it slow to change.

The benefits for these two cases are for a single year, based on the assumption that less capacity was built in the past. If future reserve margin is allowed to decrease relative to the current target level it may be reasonable to take a present value of the future savings due to such a policy. These future savings would depend upon the type of plant in which investment would otherwise be made, but if they were to remain the same for 30 years then the net present value would be 1169 95$/kW for the first case. It is not reasonable to assume a 30 year life for the nuclear case, because it is based on current depreciation and remaining lifetimes, but solely for comparison with the other values studied it would be a negative 401 95$/kW. The first case result is somewhat less than the current cost of a coal-fired plant (approximately 1385 95$/kW for a 300 MW subcritical unit[28]), and is significantly higher than

[28] Electric Power Research Institute, *Technology Assessment Guide,* 1993, Exhibit 2, p. 8-27.

the more likely future avoided capacity which is an advanced combined cycle unit, at 682 95$/kW for 500 MW[29].

The amount of benefit from a smaller reserve margin can obviously be quite significant if the whole system is reduced and not just baseload units, so the question is how much reserve margin is really needed and how can it be reduced to obtain this value. Reserve margin is necessary for reliability in case of outages due to maintenance and breakdowns. Additional reserve margin may be considered necessary due to the amount of time before new capacity can be brought into service and the uncertainty of future load growth during this period.

The simplest way to reduce reserve margin would simply be to avoid construction of new capacity and wait until load growth reduces it naturally. As shown in Figure 4.2, the current NEPOOL reserve margin is significantly above the historic national average. It is less clear how much reduction in the reliability of service to customers would be produced by a lower reserve margin, whether this decrease would be less acceptable now than it apparently was in the historic past, and indeed whether or how any correlation between such a gross measure as reserve margin and customer reliability will endure competitive restructuring of the industry.

Fortunately there are other measures which seem to make a lower reserve margin acceptable. The most obvious is to decrease outages of existing plants. This is difficult to do because reducing unplanned outages generally require increased maintenance outages. Increased use of acoustic and other plant diagnostics during operation are one trend that is already helping to find problems before unplanned outages occur, but there is already enough incentive to reduce outages that further major advances are unlikely.

The next two most obvious ways to reduce reserve margin is to build plants which are smaller and require shorter construction lead times. These measures are obviously interrelated, but both help in different ways. Smaller plants help because they reduce the temporary increase in reserve margin which occurs when they start operation. This benefit has been measured in

[29] New England regional database maintained by the Analysis Group for Regional Electricity Alternatives, M.I.T. Energy Lab.

Section 5.2 below. The shorter lead time is also valuable because it reduces the necessary time horizon for forecasting and hence the uncertainty of the forecast load. Obviously, increasing capacity by building a nuclear (or any other) plant requiring a ten year lead time means planning to meet the upper range of a ten year load forecast for the sake of security and thus taking the risk of overbuilding capacity. Improved load forecasting can also reduce the risk of overbuilding, but since load growth is primarily based on regional economic growth the only currently significant way of doing this is to reduce the forecasting time horizon.

Less obvious are the roles of energy efficiency and load management in assisting reduced reserve margins. Increasing energy efficiency will slow load growth and slow the decrease in reserve margins, which does not reduce the balance of depreciated capital cost that must be paid either by ratepayers or shareholders (whether or not the capacity is a stranded asset). However by slowing load growth, energy efficiency reduces the necessary reserve margin (in MW, not %) and also reduces the variability in forecast load which planned construction must meet. Peak shifting by load management also reduces the required reserve margin (measured in MW and not %), because a system with a higher load factor requires less total capacity to meet the same total energy requirements.

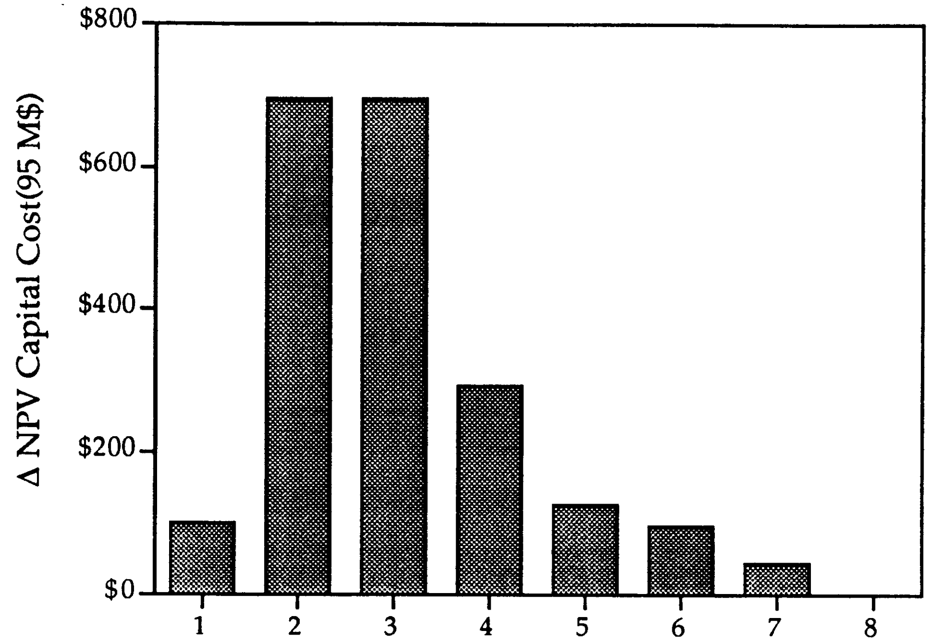
5.2 Unit Size

As observed in the preceding section, systematically smaller unit size is one way of reducing system reserve margin. The value for a single new unit however lies in reducing the sudden rise (or step function) above the target reserve margin when the unit starts operation, rather than in reducing the underlying, long term target level of reserve margin as was considered above. The value of size for a single new unit is therefore relative to the rate of system load growth because this determines how long the excess capacity above the target reserve margin will endure.

As described in Chapter 4, this section considers the cost of adding 1360 MW of new capacity either by an advanced light water reactor or by eight 170 MW modular high temperature gas cooled reactors added all at once, four every four years, two every two years, or one every year. This is equivalent to reducing new unit size geometrically from 1360 MW to 680 MW, 340 MW and finally 170 MW. The number of cases modeled was increased from five to eight by adding three cases for capital cost sensitivity analysis. The first sensitivity case increases the capital cost of the ALWR from the base value of 1370 94$/kW to equal the MHTGR cost of 1800 94$/kW. The second two sensitivity cases were formed by changing the average MHTGR cost, so that the first unit of every four includes common facilities at a cost of 2630 94$/kW, and the second, third and fourth units have a reduced cost of 1524 94$/kW.

The results of this analysis are shown in Figures 5.5 through 5.9 below. The legends for these figures summarize the description of the eight cases analyzed which was given in Table 4.6 by showing the technology, size, cost, and schedule for the number of units which come on-line in the years 2001 through 2008. These figures show the relative differences between the eight cases in the 20 year net present value of new system capital costs, variable operating cost, and total cost. Because the results are relative one case must be considered the reference case, and for the purposes of graphical clarity this case was chosen to be number eight. Although the results of this section are given relative to case eight, for reference the absolute capital, variable and total net present value costs for case eight are $3,256, $34,777, and $38,033 million respectively. The capital costs calculated by EGEAS are only for new units, including the nuclear units and the fossil units common to all eight cases. They do not include capital recovery costs for existing units, but since these are the same for all eight cases this does not matter in the relative results presented below.

Figure 5.5 - Change in NPV of New Capital Cost Due to Unit Size



1) ALWR _1360_1370_10000000
2) ALWR _1360_1800_10000000
3) MHTGR_170_1800_80000000
4) MHTGR_170_1800_40004000
6) MHTGR_170_1800_20202020
8) MHTGR_170_1800_11111111
5) MHTGR_170_2630_10001000
MHTGR_170_1524_10201020
7) MHTGR_170_2630_10001000
MHTGR_170_1524_01110111

Key: Reactor_MW_$ /kW_# to come on-line in Yrs. 2001-2008

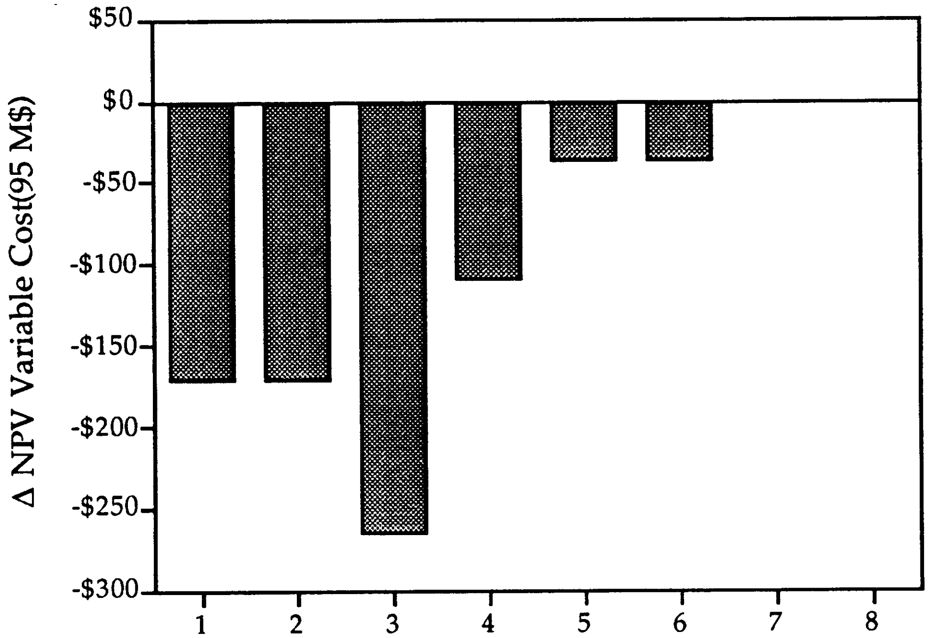
This figure shows the net present value of savings in capital cost expenditures due to the reduction in ALWR unit size for cases 3 through 8. Cases 1 and 2 are ALWR cases presented for comparison. Case 1 is based on an EPRI cost of 1370 94$/kW which seemed unrealistically low, while the case 2 price of 1800 94$/kW was chosen to be equal to the ALWR price. A more recent expert opinion of the ALWR price however was 1500 96$/kW or 1433 94$/kW[30]. The difference between the capital costs for cases 1 and 2 (3508 v. 4104 or 596 million 95$) is not simply the capacity (1360 MW) times the cost difference (1800 - 1370 or 430 94$/kW) because the base year inputs are in 1994 dollars, and the EGEAS model results include the construction cost trajectory, AFUDC, CWIP, taxes, and weighted rate of return to produce a stream of annual capital recovery costs starting in 1995 whose net present value difference is given in 1995 dollars.

[30] Private conversation with Dr. Regis Matzie, Vice President of Nuclear Systems Engineering, Asea Brown Boveri, Inc., August 1996.

The NPV capital costs for the ALWR scenarios decrease smoothly for cases 3 through 8, with values of $3951, $3547, $3382, $3352, $3301, and $3256 million, respectively. This decrease is solely due to the fact that as the amount of capacity built at one time decreases from 1360 to 170 MW, construction costs are moved further into the future so that their discounted value decreases. Recall that in cases 5 and 7 the first of every four MHTGR units includes the cost of common facilities. These cases fall into the smooth decrease of cases 4, 6 and 8 because they are intermediate steps in pushing the capital costs further into the future. As mentioned before, case 8 was the reference case against which the others were compared, so its cost above is zero. It is possible to make the unit additions still smaller until they are effectively continuous with a different technology such as DSM or photovoltaics, but this would require EGEAS to model and report sub-year time periods. EGEAS can do this, but it would raise seasonal modeling issues, and for strategic planning annual increments are usually the smallest used. Also, it is clear from the decreasing slope of cases 3 through 8 above that most of the benefit of reduced unit size has already been captured by the geometric progression down to one eighth of original capacity.

Figure 5.6 below shows the changes in the net present value of the 20 years of annual NEPOOL total dispatch costs (chiefly fuel costs and variable O&M). As before, case 8 is the reference case so it is the zero against which the other cases are compared.

Figure 5.6 - Change in NPV System Dispatch Cost Due to Unit Size



1) ALWR _1360_1370_10000000
3) MHTGR_170_1800_80000000
6) MHTGR_170_1800_20202020
5) MHTGR_170_2630_10001000
MHTGR_170_1524_10201020

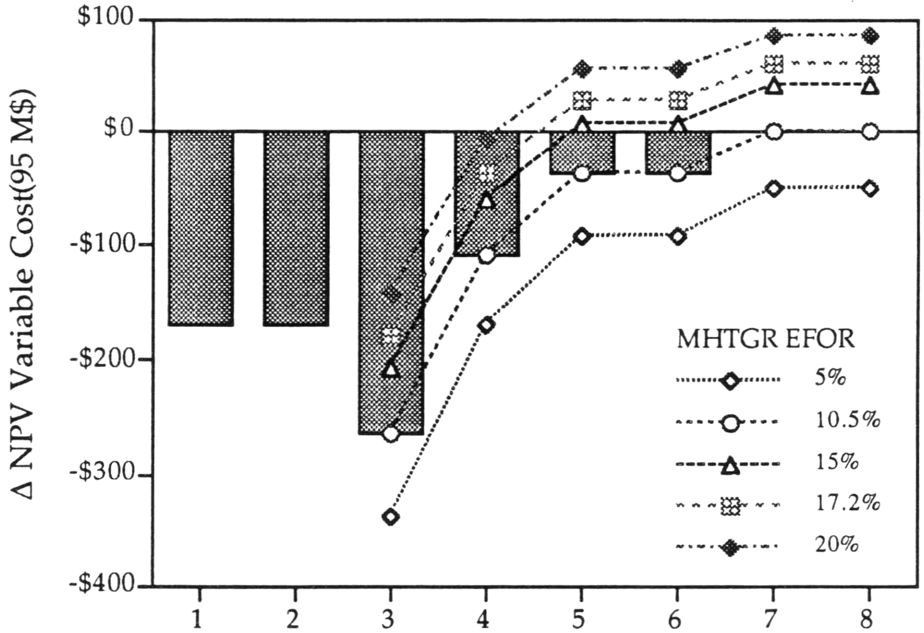
2) ALWR _1360_1800_10000000
4) MHTGR_170_1800_40004000
8) MHTGR_170_1800_11111111
7) MHTGR_170_2630_10001000
MHTGR_170_1524_01110111

Key: Reactor_MW_$ /kW_# to come on-line in Yrs. 2001-2008

This figure shows that the two ALWR cases are both $170 million cheaper than case 8. They are equal because the capital cost of the two cases does not affect their operating cost. Case 3 is $265 million cheaper than case 8 and $95 million cheaper than cases 1 and 2 even though the MHTGR has a higher dispatch cost than the ALWR (10.33 v. 5.93 94$/MWh, compared to current NEPOOL nuclear units which range from 5.4 to 6.2 94$/MWh). The difference is that the MHTGR produces more energy because it has a higher capacity factor than the ALWR, with an equivalent outage rate of 10.5% v. 17.2% respectively for unplanned forced outages and planned maintenance outages. This energy from the MHTGR unit is sufficiently cheaper than the energy it displaces from units higher in the dispatch order that it makes up for its cost premium over the ALWR. This is only true however when both units are built with 1360 MW of capacity in the year 2001. As more, smaller MHTGR units are built further into the future in cases 4 through 8, the amount of generation from more expensive units grows. Plus, this smaller benefit due to cheap variable cost is discounted more as it occurs further into the future, so that cases 4 through 6 have savings of $110, $37 and $37 million with respect to case 8. As with cases 1 and 2, cases 5 and 6 and cases 7 and 8 have equal costs because their differences in capital cost do not affect their equal dispatch costs.

As discussed above, the MHTGR has a lower dispatch cost and higher capacity factor than the ALWR, and the capacity factor can give the MHTGR lower total system dispatch costs, depending upon unit size and the amount of excess capacity. The analysis has already considered sensitivity to MHTGR unit size and ALWR capital costs, but these results also indicate that sensitivity analysis of dispatch cost and capacity factor may also be worthwhile. Of these two, dispatch cost is less interesting because it would take a large change in relative dispatch costs to make a change in the system dispatch order. Without the system dispatch effects of such a change in dispatch order, the sensitivity analysis of dispatch costs is relatively simple. On the other hand, changes in capacity factor require system modeling to assess their impacts. As noted in Chapter 4, the equivalent forced outage rate (EFOR) was used to include both forced outages and maintenance, so that an EFOR of 10% would mean a capacity factor fo 90%. EFOR for the MHTGR design was varied from 5% to 20%, including the design base case of 10.5% and the ALWR level of 17.2%. Results for these sensitivity cases are shown below in Figure 5.7, which show the results as lines superimposed on the bar graph results of Figure 5.6 above.

Figure 5.7 - Dependence of MHTGR Total Dispatch Costs on Capacity Factor



1) ALWR _1360_1370_10000000
3) MHTGR_170_1800_80000000
6) MHTGR_170_1800_20202020
5) MHTGR_170_2630_10001000
MHTGR_170_1524_10201020

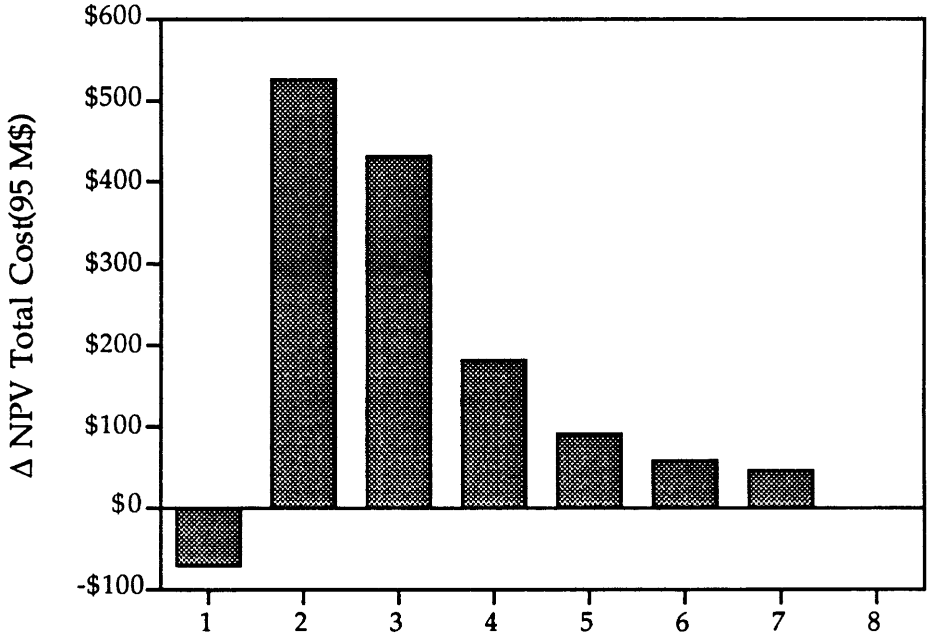
2) ALWR _1360_1800_10000000
4) MHTGR_170_1800_40004000
8) MHTGR_170_1800_11111111
7) MHTGR_170_2630_10001000
MHTGR_170_1524_01110111

Key: Reactor_MW_$/kW_# to come on-line in Yrs. 2001-2008

As this figure shows, the effects of capacity factor can be significant, and on a scale with the cost effects already found for unit size. Second, the effects of capacity factor are much larger than the effect of differences in dispatch cost between the ALWR and MHTGR units. Comparing the ALWR (case 1 or 2) to the MHTGR built with the same size (case 3) and capacity factor (an EFOR of 17.2%, shown by the crosshatched square) shows a NPV difference of only 8 million 95$ due to the difference in dispatch costs (5.9 v. 10.3 94$/MWh). Third, the impact of changes in capacity factor is approximately linear for each MHTGR case, decreasing slightly from case 3 to case 8 and having an average NPV value of 51 million 95$ for each 5% change. The chief conclusion from this sensitivity analysis is that capacity factor has an effect approximately equal to effective unit size for the MHTGR, and both need to be considered in making an investment decision.

The relative impact of the eight unit size cases considered on total NPV system cost is shown below in Figure 5.8, which simply shows the sum of the capital and variable costs presented in Figures 5.5 and 5.6 above.

Figure 5.8 - Change in Total NPV System Cost Due to Unit Size



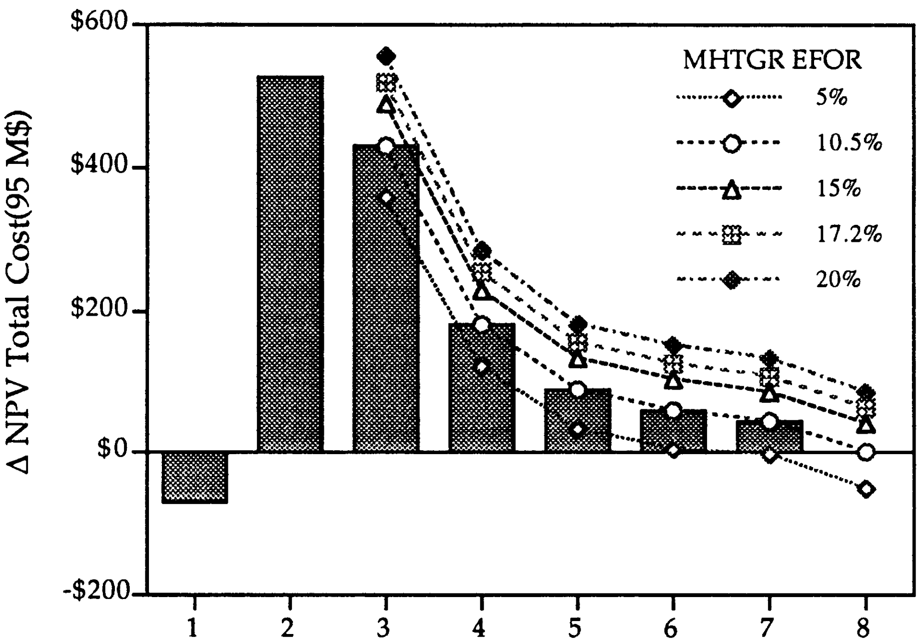
1) ALWR _1360_1370_10000000
2) ALWR _1360_1800_10000000
3) MHTGR_170_1800_80000000
4) MHTGR_170_1800_40004000
6) MHTGR_170_1800_20202020
8) MHTGR_170_1800_11111111
5) MHTGR_170_2630_10001000
MHTGR_170_1524_10201020
7) MHTGR_170_2630_10001000
MHTGR_170_1524_01110111

Key: Reactor_MW_$ /kW_# to come on-line in Yrs. 2001-2008

Although the first ALWR case appears most attractive, this is based on a low and conceivably unrealistic estimated capital cost. For the MHTGR units, this figure shows that the capital cost benefits outweigh the variable cost increases as smaller units are added more often into the future, with a net present value reduction of $430 million as unit size is decreased eight fold from 1360 to 170 MW. Assuming a 30 year life and 10% interest rate, the annual benefit of this eight fold reduction in unit size is $45.6 million per year. It is also clear that given equal capital costs, the increased base case capacity factor of the MHTGR can give it an advantage over the ALWR that can range from $95 to $525 million or $10.1 to $55.7 million per year, depending upon the number of reactors built at one time. Using the dependence of variable cost for the MHTGR upon capacity factor shown in

Figure 5.7 above gives the total system cost sensitivity results shown below in Figure 5.9. As before, results for different EFOR levels are presented as lines superimposed on the based case bar graph results of Figure 5.8.

Figure 5.9 - Dependence of MHTGR Total System Costs on Capacity Factor



1) ALWR _1360_1370_10000000
2) ALWR _1360_1800_10000000
3) MHTGR_170_1800_80000000
4) MHTGR_170_1800_40004000
6) MHTGR_170_1800_20202020
8) MHTGR_170_1800_11111111
5) MHTGR_170_2630_10001000 MHTGR_170_1524_10201020
7) MHTGR_170_2630_10001000 MHTGR_170_1524_01110111

Key: Reactor_MW_$ /kW_# to come on-line in Yrs. 2001-2008

On the high cost end, this figure shows the obvious result that the ALWR and MHTGR technologies will have the same impact on total system costs if they have the same capital cost (1800 94$/kW) and capacity factor (82.8%). Fuel cost differences are so small that they are difficult to see. On the low end, a *very* good EFOR of 5% would give the MHTGR a capacity factor of 95% and a net cost low enough to offset almost all the capital cost advantage of the ALWR (1370 v. 1800 94$/kW).

If the EPRI estimate of capital cost of 1370 $/kW for the ALWR is correct, then it still has a $72 million or $7.64 million per year advantage over the MHTGR added as 170 MW single units and having the base case EFOR of

10.5%. This is not a big difference. In fact, by looking at the difference between cases 1 and 2 it is clear that the capital costs of the ALWR would only have to rise to 1422 94$/kW before the MHTGR is competitive with it. This is less than one expert's opinion quoted above of 1433 94$/kW. By looking at the cost and capacity differences between cases 3, 4, 6, and 8 (all MHTGR units having equal cost), the marginal and average benefit of unit size reduction can be found, as shown in Table 5.2 below.

Table 5.2 - Marginal and Average Benefit of Unit Size Reduction

Size Reduction				
From (MW)	1360	680	340	1360.0
To (MW)	680	340	170	170.0
NPV (95 M$)				
Capital Cost	404.4	195.0	95.9	695.3
Variable Cost	-155.0	-73.0	-37.0	-265.0
Total Cost	249.4	122.0	58.9	430.3
Marginal Benefit				Average
(95 $/kW)	366.7	358.9	346.3	361.6
(95$/kW/yr)	38.90	38.07	36.74	38.35

Notice that the average value of 362 95$/kW for MHTGR unit size reduction is slightly over the 20% of the 1800 94$/kW capital cost. This is a large enough amount to indicate a strong drive for smaller plants. Also, it is interesting to compare the annualized benefit for unit size ($38.4/kW/yr.) with the same annualized benefit for overall reserve margin from Section 5.1 of $96.6/kW/yr.). It makes sense that the unit size value is approximately 40% of the reserve margin value, because the unit size cost of excess capacity is only incurred for part of the 20 year study period.

As mentioned in Chapter 3, the results of this section for reduced unit size represent a minimum. Building smaller units consecutively instead of as a single large unit, has an another benefit due to the additional flexibility in planning. If load growth is low, or the relative costs of different fuels shift it is possible to simply delay or stop building future units. Additional benefits can be obtained if the construction period is reduced so that unit commitment decisions can be made with less lead-time and better information. Although these two benefits were not explored in the present analysis (the ALWR and MHTGR units both have a supposed 5 year construction period), the financial management tools of options theory, such as contingent claims analysis, can analyze the benefits of these and other choices under conditions of stochastic uncertainty. The field of options theory is based upon the study of financial options (such as puts, calls, and derivative) pioneered by Black and Sholes[31] and Merton[32]. When conditions approximate certain assumptions which are plausible for financial markets (i.e. market equilibrium, risk free alternatives, and option independence), these tools can be used in many areas like capital acquisition under uncertainty. Options theory as applied to the electric utility industry has a growing literature, including optimization models using mixed integer and stochastic programming techniques[33]. It is also gaining direct use by utilities such as Boston Edison which has used it to structure its RFPs for new capacity and to analyze the bids submitted[34]. Other specific applications include the use of contingent claims analysis to analyze the values of exhaust gas scrubbers v. fuel switching for coal plants[35], and coal gasifiers v. natural gas for combined cycle plants[36]. The most direct application found of contingent claims analysis to the MHTGR technology considered in this section is by Thomas[37], which includes consideration of value over plant lifetime, the value of construction lead times, the value of modular flexibility, the value of capital cost intensivity, and the value of dual inputs or outputs (e.g. fuel switching or trading off electric generation v. process heat production).

Although options theory has many advantages over the conventional discounted cash flow (DCF) analysis that produces levelized busbar costs, it also has some problems. Chief among these is that all the emphasis is still

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[31] Black, F. and M. Scholes, "The Pricing of Options and Corporate Liabilities", *Journal of Political Economics*, 81, 1973, pp. 637-654.

[32] Merton, R. C.,"Theory of Rational Option Pricing", *Bell Journal of Economics*, Vol. 4, Spring 1973, pp. 141-183.

[33] Bienstock, D. and J.F. Shapiro, "Optimizing Resource Acquisition Decisions by Stochastic Programming", *Management Science*, Vol. 34, No. 2, February 1988, pp. 215-229.

[34] Boston Edison presentation at M.I.T. Electric Utility Program Workshop, September 1995.

[35] Herbelot, O., *Option Valuation of Flexible Investments: The Case of a Scrubber for a Coal Fired Power Plant*, M.I.T. Energy Lab Working Paper MIT-CEEPR 94-001WP, March 1994.

[36] Herbelot, O., *Option Valuation of Flexible Investments: The Case of a Coal Gasifier*, M.I.T. Energy Lab Working Paper MIT-CEEPR 94-002WP, March 1994.

[37] Thomas, J. S., *Modular Gas-Cooled Reactor Economics: The Application of Contingent-Claims Analysis*, S.M. Thesis, M.I.T, October 1991.

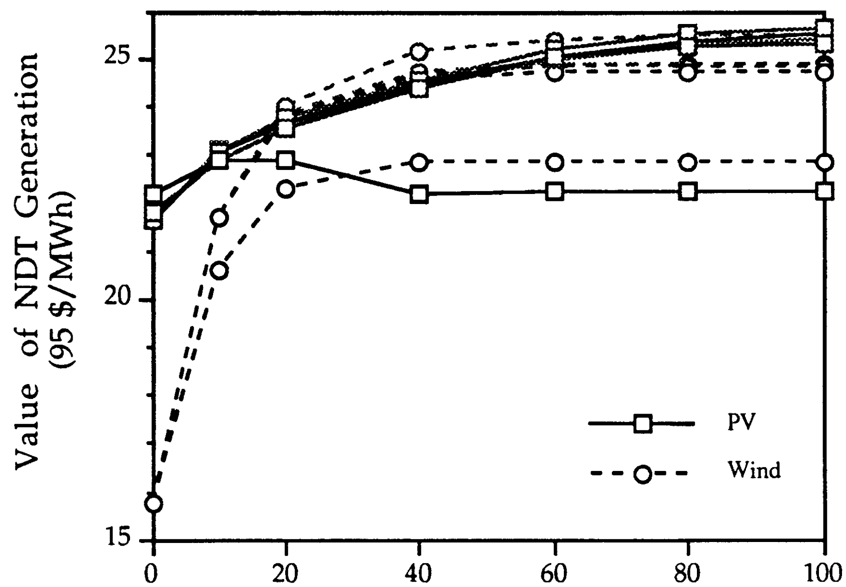
upon analyzing a specific utility option, and not upon how the option interacts with the existing system. This suggests that there may be ways to improve option analysis by incorporating system simulation modeling for contingency valuation at nodes of the decision tree which is structured to reflect the flexible option choices available.

5.3 Dispatchability of Uncontrolled Resources

Some resources like photovoltaic and wind generation are undispatchable, while other resources may only have limited dispatchability, like hydropower with limited dam capacity or cogeneration that must supply both heat and electricity. Because the marginal cost of electricity varies over time, the value of electricity from an uncontrolled or limited dispatch resource depends upon its correlation with system load. The value of resource dispatchability can be measured by varying it through the addition of both storage capacity and inverter capacity in different amounts. (Inverter capacity is required to convert NDT generation and DC storage to match the AC grid's wave form and voltage, and because of storage, inverter capacity can exceed 100% of NDT generation capacity). This analysis has been done for both photovoltaic and wind resource generation, and Section 5.3 describes the characteristics of the technologies chosen, the range of storage and inverter parameters chosen, the storage optimization algorithm developed and the marginal cost supply curve methodology used. This section describes the results of the analysis, describing the value supply curves derived and how they depend on dispatchability, initial time distribution of the resources, and energy losses.

The first graph in Figure 5.10 below shows the total value per MWh of both photovoltaic and wind generation for the year 1995 (in 1995 dollars), as a function of storage capacity, where storage is expressed as a percentage of the maximum day's generation for the year. This graph shows separate curves for different levels of inverter capacity, but for clarity all curves are only labeled as wind or solar.

Figure 5.10 - Value per MWh of NDT Generation
as a Function of Storage Capacity



Several things are clear from this graph. First, without any storage the average value of energy from wind generation (15.8 $/MWh) is less than that from solar generation (21.6 $/MWh, based on median year weather data for the two sites selected . This difference of 5.8 $/MWh is due to the fact that solar generation is more correlated to system load than wind generation. Load is greater during the day and NEPOOL is now a summer peaking utility so that solar generation without storage occurs at hours with higher system marginal cost. Since these results are per MWh of energy, this is true regardless of the different capacity factors and losses of the two technologies which are also very important to their attractiveness.

Second, with adequate storage added the average value of electricity from both resources is approximately equal to 25 $/MWh. This means that the value per MWh of adding storage for wind generation is higher (approximately 9 $/MWh) than for solar generation (approximately 4 $/MWh). The value of wind generation storage also increases more quickly with storage than for solar, but both reach the same maximum value. This is because the value of the electricity is based only the NEPOOL marginal cost supply curve and the time distribution of generation, and with sufficient storage both technologies can shift their generation to the most valuable hours.

Third, the average value of inverter capacity can be greater for PV generation. The two families of wind and PV curves overlap in Figure 5.10 above, but the lowest wind and solar curves represent inverter capacity that is 25% of generation capacity. Increasing inverter capacity from 25% to 100% can increase the average value per MWh by about 3.2 $/MWh for PV generation, compared to 1.9 $/MWh for wind generation. This value comes from the fact that limited inverter capacity can limit generation at peak load hours where the marginal cost of electricity is the highest. At 25% inverter capacity, the PV curve rises and then falls, whereas the wind curve rises monotonically. This is due to the fact that the average PV value starts out higher (due to the greater correlation with system load), and the fact that the PV generation starts low and then increases as shown in Figure 5.15 below.

While Figure 5.10 above shows the average energy value per MWh, it is also worthwhile looking at the total value of generation and total energy generated. Figures 5.11 and 5.12 below show the total value of energy generated separately for the PV and wind plants.

Figure 5.11 - Value of Total 1995 Generation as a Function of Storage Capacity for a 1000 MWe PV Plant

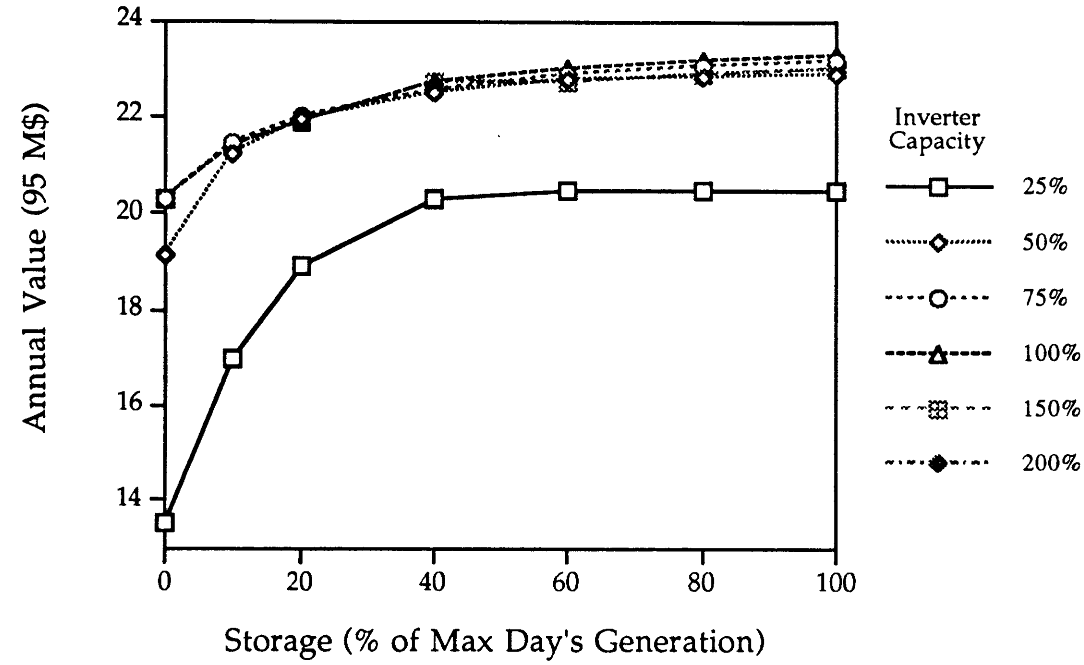
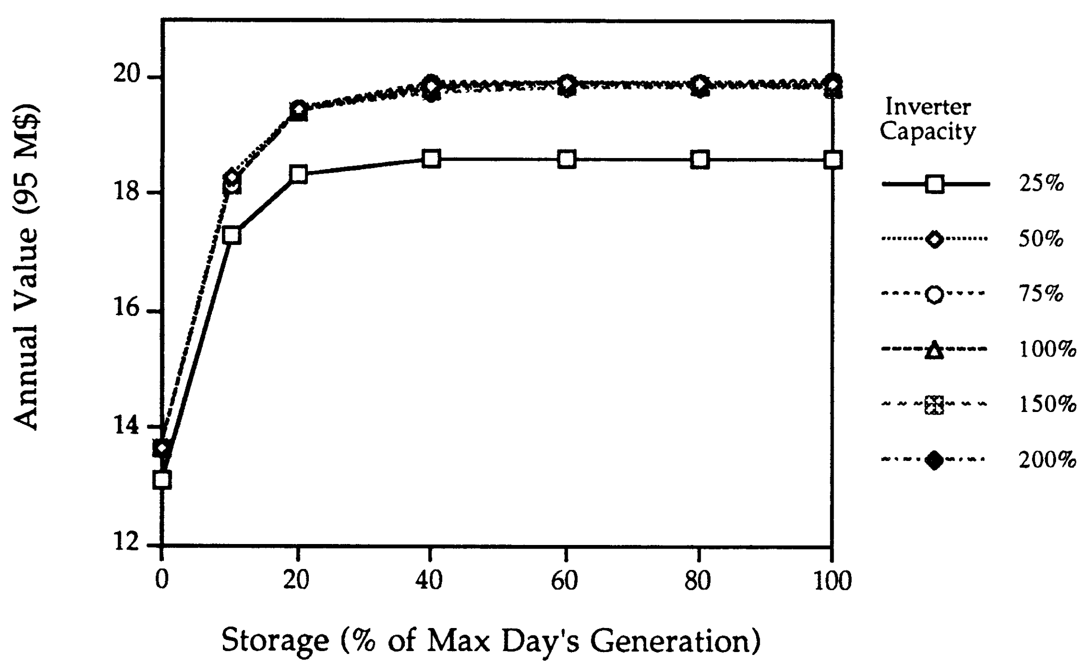


Figure 5.12 - Value of Total 1995 Generation as a Function of Storage Capacity for a 1000 MWe Wind Plant



These graphs show that given a minimum of inverter capacity, the maximum value of adding storage capacity is $2.8 million for PV and $6.2 million for wind generation. For both resources it is clear that the marginal benefit of additional storage capacity falls off rapidly, and after storage capacity reaches approximately 40% of the peak day's generation there is little benefit in additional storage. For wind the initial marginal benefit of storage is greater (the slope is steeper), but this decreases quickly. After 40% storage is reached storage benefits for wind are basically flat, whereas for PV generation the total values continues to rise slightly. Table 5.3 below shows the marginal benefits of storage in absolute dollars and in dollars per MWh of storage capacity, neglecting the lower cases with inadequate inverter capacity. To compare these annual benefits of storage with the capital costs of purchasing storage capacity these annual benefits must be converted to the net present value of the stream of future savings. Using the same NPV factor as before of 9.43, the NPV benefits are also shown in the table below. Note that this table gives results in dollars per MWh of *storage* capacity, which should not be confused with MWh of NDT generation.

Table 5.3 - Marginal Benefits of Storage for PV and Wind Generation

Storage Increment							Total	
From (%)	0	10	20	40	60	80	0	0
To (%)	10	20	40	60	80	100	40	100
PV (MWh)	556	556	1,113	1,113	1,113	1,113	2,226	5,564
Wind (MWh)	665	665	1,330	1,330	1,330	1,330	2,661	6,652
Marginal Benefit							Average	
PV								
(95M$)	1.336	0.543	0.707	0.173	0.158	0.096	2.586	3.013
(95 $/MWh/yr)	2,400	976	635	155	142	87	1,162	542
(95$/MWh)	22,628	9,201	5,990	1,462	1,342	817	10,953	5,105
Wind								
(95M$)	4.505	1.249	0.392	0.058	0.005	0.000	6.209	6.209
(95 $/MWh/yr)	6,772	1,878	294	44	4	0	2,334	933
(95$/MWh)	63,841	17,707	2,776	410	37	0	21,999	8,799

Note: Marginal benefits are averaged over inverter capacities from 50% to 200%.

These benefits do not depend upon the cost of PV or wind generation, or upon the cost of storage or inverter capacity. However because the results put a value on storage and inverter capacity, it is instructive to look at the costs of these for the purposes of comparison. The cost of battery storage can vary widely, depending primarily upon the interrelated factors of battery lifetime (both in years and cycles) and how deep the average discharge cycle of the battery is intended to be. For information on the range of battery costs, a local consulting firm was consulted [38]. Battery costs can range from $75 to over $800 per 100 amp hours at 12 volts, or $62 to $666 per kWh. Cheap batteries ($100 or less) can last 5 years without problems given a low discharge cycle, but may only last 1 year with a 20% discharge cycle. Medium price batteries (usually used for marine applications) cost $130 to $150 and can last 1000 cycles at 20% discharge, 600 cycles at 50% discharge, and 300 cycles at 80% discharge. The most expensive batteries ($800) can last up to 20 years, but are generally used for backup power supplies, so they are continuously trickle charged and rarely cycled. Obviously the tradeoff is between more batteries for a lower discharge cycle or buying batteries more frequently. From this limited data, it appears that a medium cost battery at a 50% cycle is most cost effective, requiring a battery capacity twice the effective storage capacity at a cost of $250/kWh for 600 cycles. Once the battery life and the salvage value of the batteries is known, it is then possible to find the net present value of the original and replacement batteries. Assuming somewhat conservatively that 600 cycles at 50% is equal to 2 years of service, no salvage value, a 7% real interest rate and a 30 year plant life gives a net present value of $1716/kWh of effective storage capacity. Without salvage value or economies of scale, this number is conservatively high, but it gives a crude estimate of the cost of storage.

For comparison with a more specific utility application, the EPRI TAG was consulted for data on its reference battery storage designs[39]. This design is a 20 MW design sized for one hour of storage. Because of the projected deep cycle use for load leveling, the heavy duty data were used. This gives a battery first cost of 128 95$/kW. Assuming a 30 year planning horizon, a daily discharge cycle (365/yr), and interpolating from EPRI data gives a NPV replacement battery cost of of approximately 354 95$/kW, for a total of 482

[38] Conversation with Mr. Bill Kanzer of Ascension Technologies, Waltham, MA.
[39] Electric Power Research Institute, *Technology Assessment Guide*, 1993, Exhibit 43, p. 8-203 and 8-206.

95$/kW. The chief difference between these two sources appears to be economies of scale, which are based on manufacturing capacity rather than unit size. The EPRI data is based upon production of 500 MWh of storage capacity (or 25 units) per year.

Because the value of dispatchability was calculated independent of the storage technology, there are several changes to the storage algorithm that could be made to optimize storage and more accurately choose and price the battery requirements. First, in the algorithm written energy losses were fixed, rather than a function of energy in and out of storage. EPRI estimates storage losses of approximately 25% for its design, which would require some alteration of the energy swap criterion, but not the nested search for high and low hours. Second, some additional statistics could be added to track the annual distribution of discharge depth for each cycle.

Figures 5.11 and 5.12 above show that the marginal benefits of more inverter capacity decrease rapidly, but this is clearer if the horizontal axis is changed. Figures 5.13 and 5.14 below show the 1995 total value of NDT generation as a function of inverter capacity for PV and wind generation.

Figure 5.13 - Value of Total 1995 Generation as a Function of Inverter Capacity for a 1000 MWe PV Plant

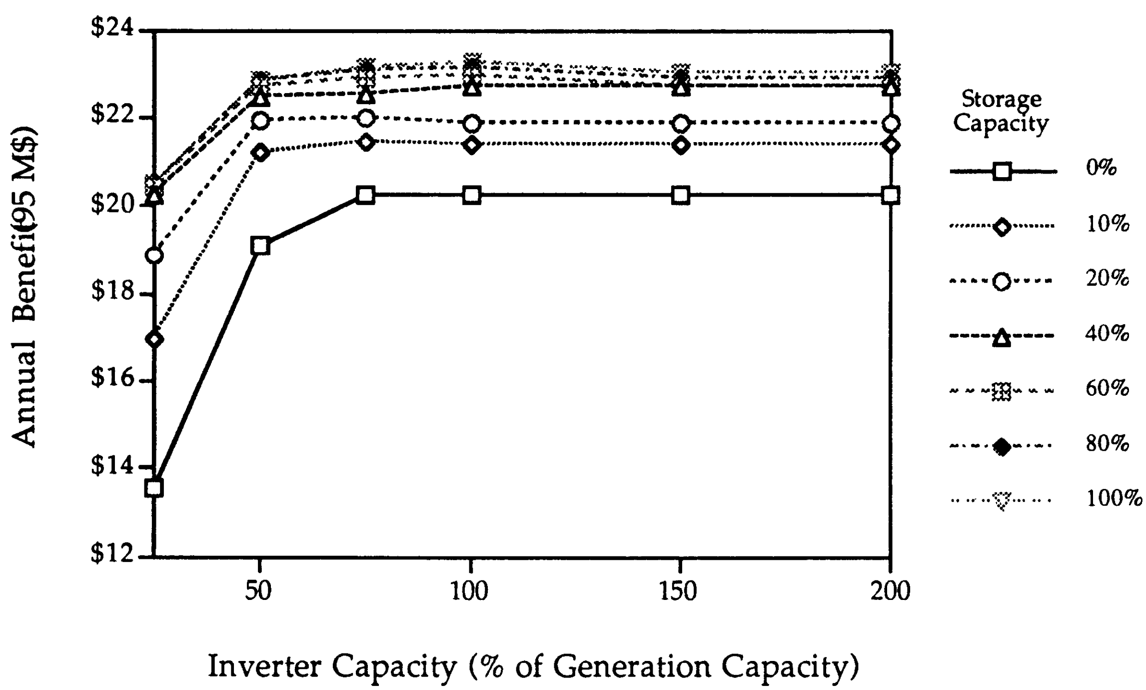
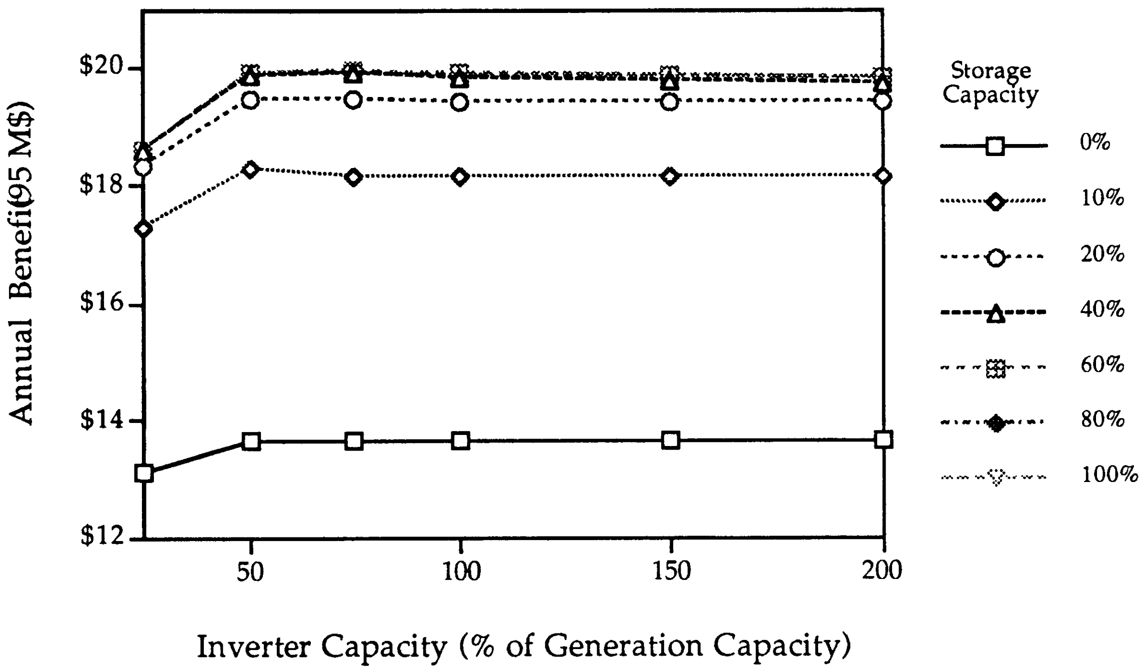


Figure 5.14 - Value of Total 1995 Generation as a Function of Inverter Capacity for a 1000 MWe Wind Plant



From these two graphs it is apparent that there is no significant benefit to increased inverter capacity above 50% of generation capacity, except for the PV case with 0% storage where there is a slight marginal benefit up to 75% inverter capacity. Second, the marginal value of inverter capacity from 25% to 50% is approximately the same for all levels of storage capacity above 10% for both wind and PV, (averaging $2.45 million for PV and $1.27 million for wind respectively). For both PV and wind the gross generation capacity is 1000 MW, but on-site generation losses were subtracted out before calculating inverter capacity. This means that 100% of inverter capacity is 909 MW for PV and 870 MW for wind, and the marginal benefit per MW from 25% to 50% is 2.70 $/kW for PV and 1.46 $/kW for wind. Inverter capacity lasts longer than battery storage capacity, and using the NPV factor of 9.43 for the assumed 30 year life means that present value marginal benefit per MW of inverter capacity is 25.41 $/kW for PV and 13.79 $/kW for wind. Table 5.4 below shows the absolute and marginal values of inverter capacity from 25% to 50% as a function of the storage capacity. Once a storage capacity of 40% has been reached, the marginal benefits of inverter capacity level out, so this table also shows the average of the columns for 40% through 100%.

Table 5.4 - Marginal Benefit of Inverter Capacity from 25% to 50%

	Storage Capacity							Average
	0%	10%	20%	40%	60%	80%	100%	40% -100%
PV (25% to 50%)								
(95M$)	5.582	4.272	3.031	2.207	2.278	2.347	2.385	2.304
(95 $/kW/yr)	24.6	18.8	13.3	9.7	10.0	10.3	10.5	10.1
(95$/kW)	231.6	177.2	125.8	91.6	94.5	97.4	99.0	95.6
Wind (25% to 50%)								
(95M$)	0.543	0.976	1.126	1.261	1.321	1.327	1.327	1.309
(95 $/kW/yr)	2.5	4.5	5.2	5.8	6.1	6.1	6.1	6.0
(95$/kW)	23.5	42.3	48.8	54.6	57.3	57.5	57.5	56.7

For comparison, the cost of inverter capacity was also surveyed using the same two sources as for storage costs. Without the economies of scale, inverter capacity is approximately $750 to $1000/kW, including conversion from DC to AC and power conditioning[40]. The EPRI data does not give inverter cost separately, but it should make up almost all of the plant's balance of cost after battery costs, which is 350 95$/kW[41]. As with batteries, economies of scale for inverter capacity depend upon manufacturing capacity and not installed unit size, and the EPRI cost is based upon a production of 2000 MW per year. From these costs, it appears that the largest marginal benefit of inverter capacity is only about two thirds the cost of inverter capacity. However, this is too simple, since the value of NDT generation without *any* inverter capacity is zero, because PV generation is DC and even if wind generation is AC it must be matched to system voltage and frequency. Even without storage capacity the inverter capacity does not have to equal the peak generation capacity, but without storage there is more incentive to keep inverter capacity high because any generation above inverter capacity must be dumped, and this is very expensive. From this perspective it is clear that the addition of storage capacity can reduce the need for inverter capacity by up to 60% from the original generation capacity with out any significant costs, and by even more with relatively minor costs. This represents a credit which can be added to the benefits of storage given above.

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40 Conversation with Mr. Bill Kanzer of Ascension Technologies, Waltham, MA.

41..Electric Power Research Institute, *Technology Assessment Guide*, 1993, Exhibit 43, p. 8-203 and 8-206.

Originally it was thought that there might be some benefit of inverter capacity greater than 100% of generation capacity to get more benefit during peak load hours. However it seems clear from the results that peak generation from the inverter is more limited by the amount of generation available in preceding hours than by inverter or storage capacity. The initial range of parameter variation for inverter capacity was from 50% to 200% (half and double the base value of 100%), but review of these preliminary results led to the addition of cases at the 25% level. The present results amply illustrate and quantify this component value, but for application to a real NDT site it is clear that sizing optimum inverter capacity would improve with more data points between 0% and 50% .

As mentioned above the real reason that value for cases with both low storage and inverter capacity falls off so dramatically is that not all generation from the resource can be delivered to the system. If there is a period with plenty of generation during several cheap hours (i.e. low system load), then the storage capacity will be full. Excess generation above the inverter capacity will then have to be dumped and the total benefit will fall. Figures 5.15 and 5.16 below confirm this by showing the total annual PV and wind generation delivered to the system load

Figure 5.15 - Total 1995 Generation as a Function of Storage Capacity for a 1000 MWe PV Plant

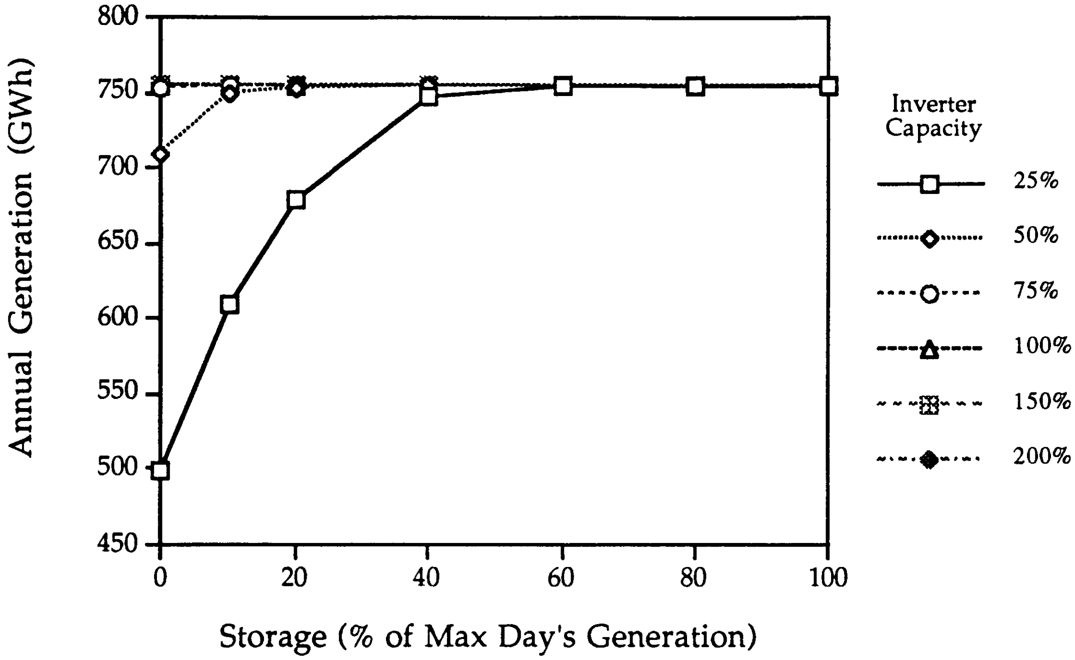
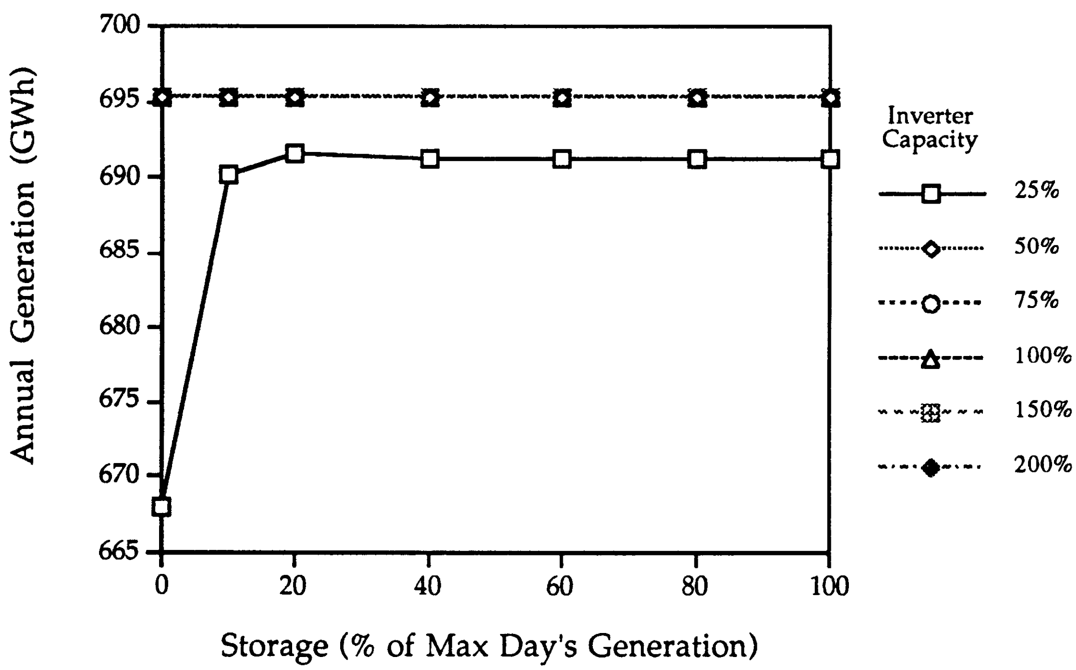


Figure 5.16 - Total 1995 Generation as a Function of Storage Capacity for a 1000 MWe Wind Plant



The first difference between these two graphs is that for PV sufficient storage capacity will eventually produce maximum energy to the system. Even with only 25% inverter capacity, 60% storage will allow the full 750 GWh to the grid. For the wind case, 25% inverter capacity limits output to 691 GWh, or 0.6% less than the full amount of 695 GWh, even with 100% storage. Second, at 25% inverter capacity level storage has a more rapid impact on energy production for wind than for PV, reaching the maximum level at 20% v. 60% of full storage.

The value supply curves for the benefits of storage and inverter capacity discussed above are independent of the technology used (although the default storage technology is assumed to be batteries). The supply cost curves for storage and inverter capacity are basically linear, although there may be some economies of scale. By using both the supply cost and benefit curves, the optimum amount of storage and inverter capacity can be found.

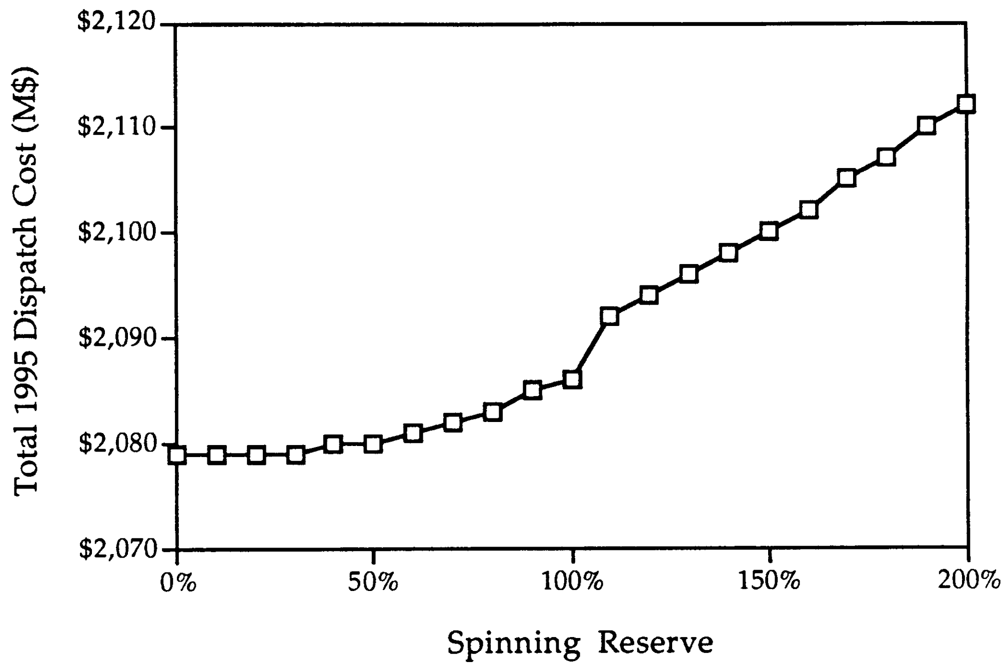
Although this section has presented results based on the amount of storage and inverter capacity, it is important to remember that the emphasis is still on the value of how dispatchable a resource is and that storage and inverter capacity is just a way of variable way of providing and measuring the value of dispatchability. The value of stand-alone storage which is charged directly by the system grid instead of by an NDT resource will be even higher than the results presented here because of the reduced constraints on the time and amount of energy available for charging. On the other hand, storage added to NDT resources may have other benefits including power quality and reliability improvements, savings of T&D capital costs, and reduced T&D energy losses, depending upon where the installation is sited. These secondary benefits have been discussed elsewhere in this thesis and are not quantified here, but since some of them are correlated with peak load (i.e. reliability and need for T&D capacity), these component values may be synergistic with the value of storage for dispatchability.

Inverter generation can also be increased effectively instantaneously, so NDT storage may form part of the synchronous spinning reserve requirement. This is possible only when there is stored energy available and inverter generation is below maximum capacity, so it is more likely to happen at below peak hours. Spinning reserve is rarely needed for emergencies so it would not affect the storage optimization algorithm. The marginal cost of the spinning reserve will be worth less than at peak hours, and this benefit should not be valued at the overall average rate quantified in the next section below, but it does form an additional benefit of storage distinct from the value of dispatchability.

5.4 Spinning Reserve

Spinning reserve is necessary for load following and in the event of forced generation or transmission outages. As described in Chapter 4, the NEPOOL Operating Procedure No. 8 (OP-8) states that the operating reserve requirement is that capacity equal to 100% of the largest contingency loss (generally the largest unit in service) should be synchronous reserve available in 10 minutes, and an additional 50% of the second largest contingency loss should be asynchronous reserve available in 30 minutes. The Polaris model combines these two reserve categories since it is an hourly model for a single standard of 150%. This section describes the results of varying this standard for the NEPOOL region. Figure 5.17 below shows the relationship between spinning reserve level and NEPOOL 1995 system operating costs.

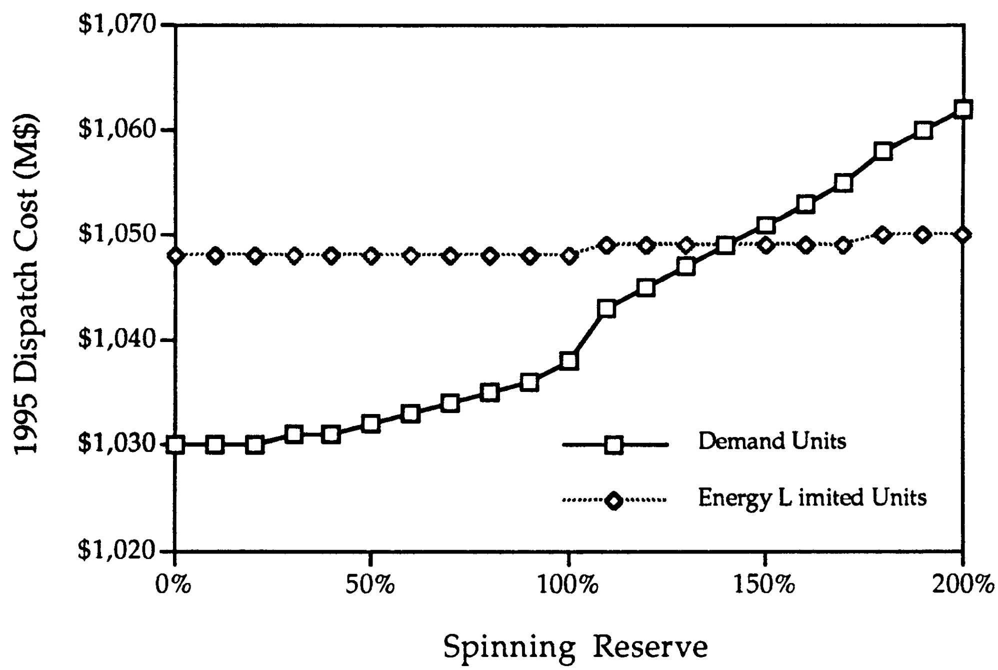
Figure 5.17 - Changes in NEPOOL Total Dispatch Cost
as a Function of Spinning Reserve (%)



As can be seen in this figure, there can be some significant benefits achieved by operating below the 150% level specified by NEPOOL Operating Procedure No. 8. However, as explained in Chapter 4, the NEPOOL system routinely operates at a spinning reserve of approximately 50% based on the level set by the North American Electric Reliability Council (NERC). This reduction from 150% to 50% reserve margin has an annual savings of $19.81 million. As shown, the bottom end of this curve is fairly flat, so further reductions in spinning reserve below 50% do not increase savings significantly. Given the current operating point for spinning reserve, this figure does not so much show the benefits of further reductions, but rather the benefit of the reductions already in place (or equivalently, the cost of any increases in spinning reserve). Spinning reserve is based on the size of the largest unit in operation, and it is unlikely that any new plants or non-dispatchable resources built will be larger than the current nuclear baseload units. If such a unit were built, or if two units (e.g. two 1000 MWe nuclear units) were to have any credible common failure modes through shared facilities then the increased level of spinning reserve (in MW) would be an additional cost which such a plant would bear. Otherwise, any cost increase will only be incurred if some new utility option increases the spinning reserve standard required above the current level of 50%.

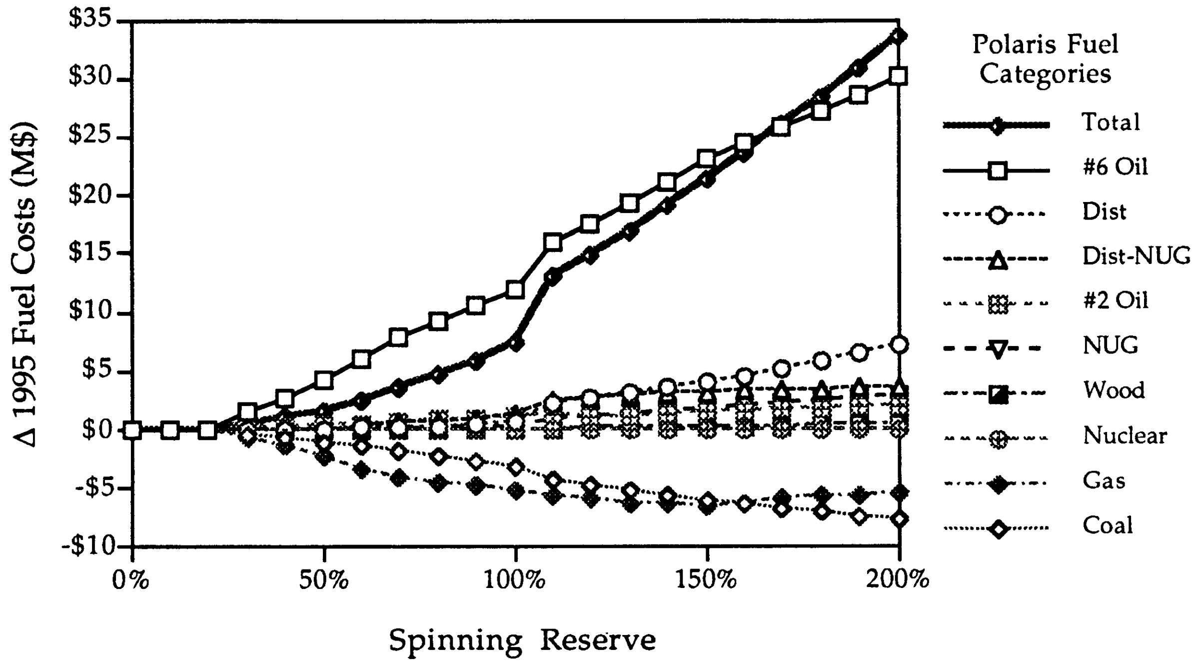
The other primary point of interest in this figure is the step function superimposed on the gradual increase from 100 to 110% . This step function was unexpected but appears reasonable, since as the spinning reserve level increases the plants which are required to provide it not only use more fuel, but at some point the mix of plants used shifts to include a different mix of fuels. The Polaris model used to model spinning reserve divides its total variable operating costs (fuel and variable O&M) between those for units which are considered to be energy limited and those for units which can be dispatched at will. Figure 5.18 below shows the total variable operating for the NEPOOL system split into these energy limited and dispatchable components. For the purposes of the Polaris model, nuclear plants are considered to be energy limited, along with hydro, some NUGs, and some power purchases, so this line basically represents base load capacity, while the demand unit line represents intermediate and peaking units.

Figure 5.18 - NEPOOL Demand and Energy Limited Unit Costs as a Function of Spinning Reserve (%)



As expected, almost all the spinning reserve related increase is reflected in the dispatch related operating costs, including the step function, while the energy limited units show only a slight, flat cost increase. To investigate this story further, Figure 5.19 below splits the costs for dispatchable units by fuel type, and shows the *changes* in fuel consumption costs as spinning reserve increases. The fuel categories shown are those present in the NEPOOL Polaris database, and includes two categories for non-utility generators.

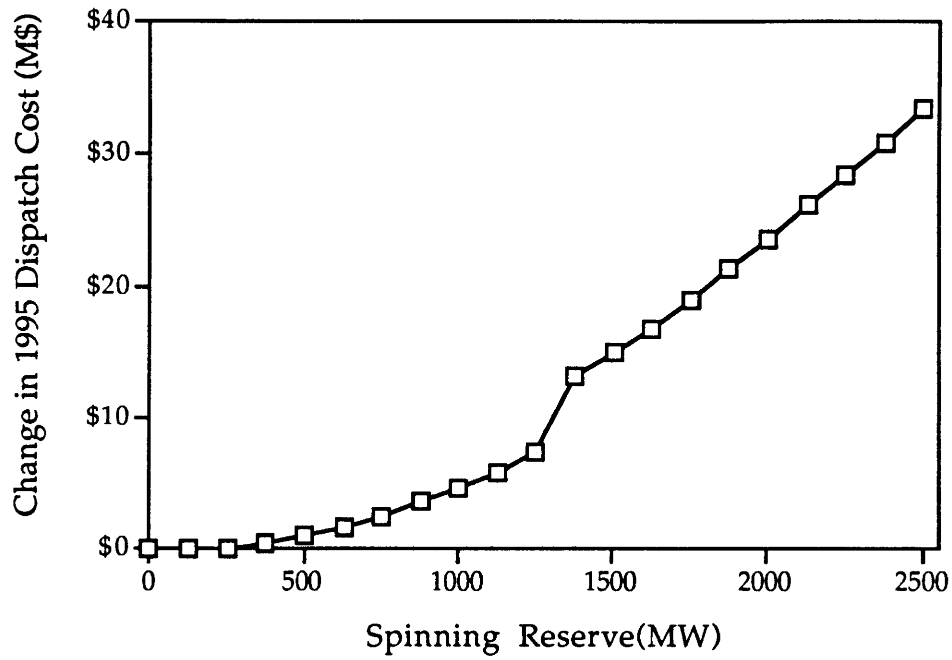
Figure 5.19 - Changes in NEPOOL Fuel Costs
as a Function of Spinning Reserve (%)



Based on this figure it can be seen that as the spinning reserve level increases, the sudden step function cost increase is primarily the effect of increased consumption of number six fuel oil. A slight increase in distillate use at this point is offset by a slight decrease in coal use.

Although the graphs above have show changes in costs as a function of the percent spinning reserve for the NEPOOL system, these costs are of course more directly linked to the absolute amount of spinning reserve in MW required by the percentage standard. Figure 5.20 below restates both axes, and shows the relative change in costs as a function of the absolute amount of spinning reserve. This graph is based upon the size of the single largest unit in the NEPOOL system, which is the 1253 MW Millstone Number 3 nuclear unit. This graph is also much more useful for comparison with other systems, since their largest single units will be of different sizes.

Figure 5.20 - Changes in NEPOOL Dispatch Costs
as a Function of Spinning Reserve (MW)



For comparison with the other component values calculated, the difference in total system costs between the levels of 50% and 150% of $19.81 million was divided by 100% times the 1253 MW for Millstone Number 3, to give an annual spinning reserve value of 15.81 $/kW. The uncertainty in this result is low, since it is based only on historic unit data used for the modeling year of 1995. Multiplying by the previously assumed 30 year present worth factor of 9.427 used in the other sections gives a NPV value of 149.0 $/kW. This value for spinning reserve is approximately a third of one estimate current in the industry which is approximately $4/kW/month[42]. Although this number is not based on concrete calculations, it does make some sense that the average value of spinning reserve to the system as a whole will be smaller than the value of spinning reserve to specific generating units which supply it. For either system or unit values of

[42] Ongoing conversations with Dr. Richard Tabors.

spinning reserve, the method in which the costs or benefits will be divided under a competitive marketplace remains to be determined.

Spinning reserve is one of a number of ancillary services which are necessary to secure system operation. In response to its proposed ruling on open access to power transmission, FERC received different numbers and classifications of ancillary services from Oak Ridge National Laboratory (7), NERC (12), Houston Light & Power (20), and the New York Power Pool (38). As noted by ORNL, spinning reserve was worth unbundling because there is a low cost and a high benefit for doing so[43]. FERC's Order 888 dated April 24, 1996 settled on 6 classes of required ancillary services, one of which was spinning reserve, and left open the possibility for other non-required services. The FERC order rules that the transmission provider must offer to provide spinning reserve service only to those transmission customers in its control area, and that transmission customers must pay for this service, but may acquire it from the transmission provider, a third party, or through self supply. Under one form of further deregulation, an independent system operator (ISO) would purchase spinning reserve services from independent generators and interruptible customers. Given a competitive market, the cost paid for different levels of spinning reserve by the ISO should approximate the cost curve shown in this section.

5.5 Dispatchability for Thermal Units

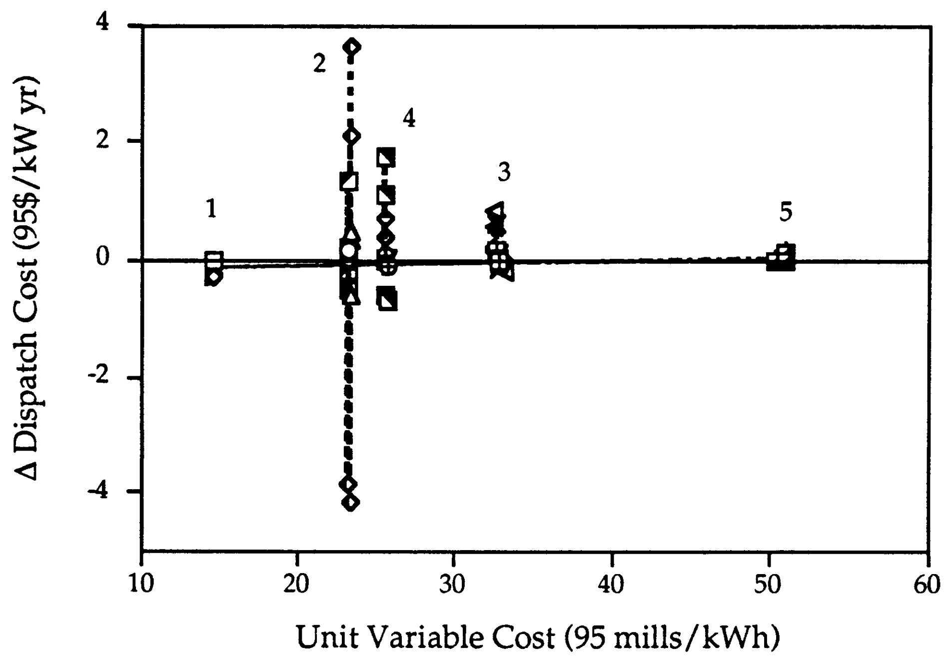
Whereas the previous section focused upon the value of dispatchability for uncontrolled resources, this section focuses upon the value of controllable generation units. Even though these units can be turned on and off on command, this dispatchability is still constrained by the physical and economic constraints discussed in Chapter 3. This section presents the results for changing the dispatch constraints on five individual, generic, thermal generating units. These units span a range of dispatch cost, fuel and technologies. Unit 1 is a coal-fired base load unit, units 2 and 3 are intermediate oil-fired units, unit 4 is gas-fired combined cycle unit, and unit 5

[43] Hirst, E. and Kirby, B., *Electric-Power Ancillary Services*, p. 2, ORNL/CON-426, Oak Ridge National Laboratory, February 1996.

As described in Chapter 4, the run time constraint is the number of hours advance notice required until a unit can be started. The down time constraint is the number of hours after a unit is shut down before it can be started up again.

It was originally expected that changing dispatch constraints would be of little value for baseload units which rarely cycle on and off, that it would be of little value for peaking units that are already very dispatchable, and that it could be of significant value for intermediate plants in the loading order. Figure 5.21 below confirms this and shows the range of changes in total system cost due to changes in both minimum run times and minimum down times plotted against the variable dispatch cost of the five generic test units modeled. Individual component value supply curves are not shown because they overlap. These curves are shown separately in following figures. Note that the results have been normalized by unit size so that units for the vertical axis are in units of $/kW.

Figure 5.21 - Change in Total Annual Dispatch Cost as a Function of Unit Variable Cost, Units 1-5



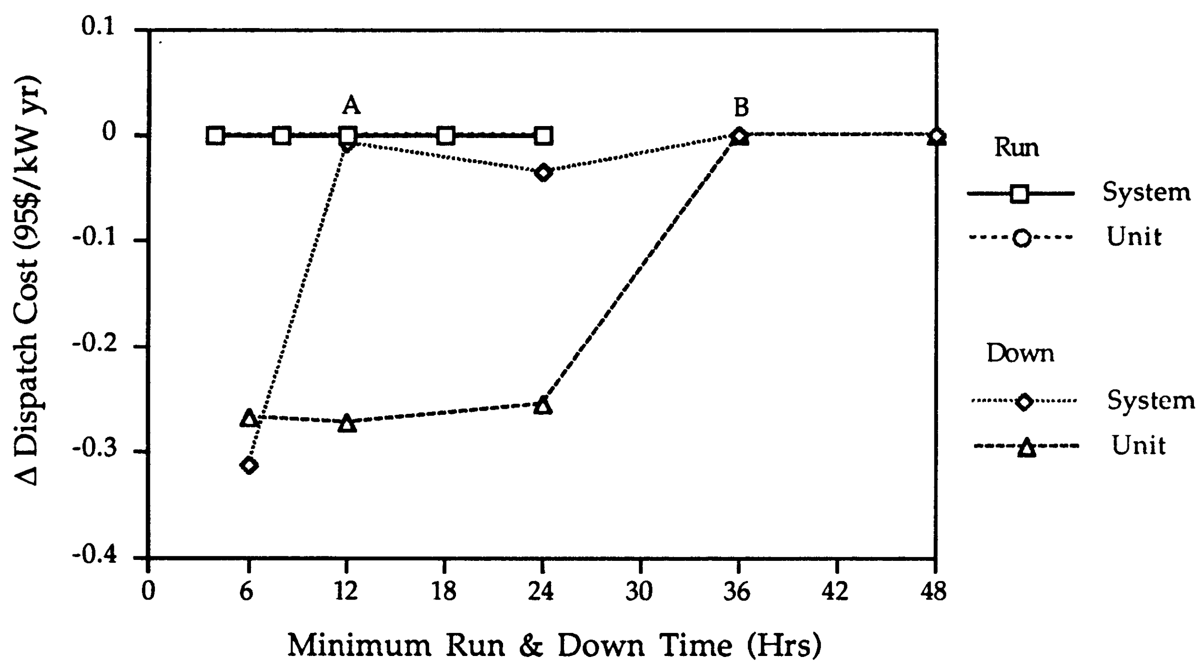
This graph confirms the original expectation that the effects of changing dispatch characteristics for an intermediate load unit can have significant effects. The variations in total costs shown are in comparison with the base values for significant effects. The variations in total costs shown are in comparison with the base values for each units minimum down time and run time parameters, as given in Chapter 4. The cost variations may be negative as the constraints are relaxed and positive as they are tightened. As can be seen, system and unit costs varied over the range of parameters modeled by as much as approximately $8/kW for generic unit number 2, $2/kW for unit number 4 and 1$/kW for unit number 3. The variation for the baseload unit 1 and the peaking unit 5 were approximately zero. The range of variation is considerably larger for unit costs than for overall system costs, as shown below in Figure 5.22 through 5.26.

Even the largest cost variation due to changes made in the dispatch constraints is small compared to total 1995 dispatch costs, approximately $0.66 million difference in system costs and $4.66 million in individual unit costs compared to total system variable dispatch costs on the order of $2.079 billion. This is because the variation is a change in operation for a single plant out of several hundred, and the largest generic unit was approximately 600 MW out of a total system capacity of 26 GW. The results of changing constraints on a single unit cannot be isolated and seen in real life because they would be obscured by random noise and the impossibility of repeating an entire year exactly except for different constraint levels. The ability of the Polaris model to repeat a year's dispatch exactly except for changes due to a single units dispatch constraints allows the results to be isolated and observed.

As figure 5.21 shows, the variable cost for unit 4 lies between units 2 and 3, instead of between units 3 and 5 as originally intended. The generating units which were removed from the system and replaced by the generic units were originally chosen based on variable cost data from the AGREA EGEAS database. The unit that was modified in size to create unit 4 had burned oil in the EGEAS database and burned natural gas in the NEPOOL Polaris database, which accounts for its change in dispatch cost. This difference between the databases gave results for unit 4 which were larger and in a position where more definition was desirable, so no additional runs were performed for a unit with the original dispatch cost of unit 4. Additional results would have been most preferred between units 1 and 2, with a variable cost of approximately 20 mills/kWh, but the number of runs which could be performed at NEES were limited.

Figure 5.21 above gives the range of variation in system and unit costs for each of the five units, but does not show the relative size of system v. unit costs or their dependence upon the hourly variation in the minimum down time and minimum run time dispatch constraints. Figures 5.22 through 5.26 below show these results for the individual generic units 1 through 5, and are each followed by discussion of their individual results.

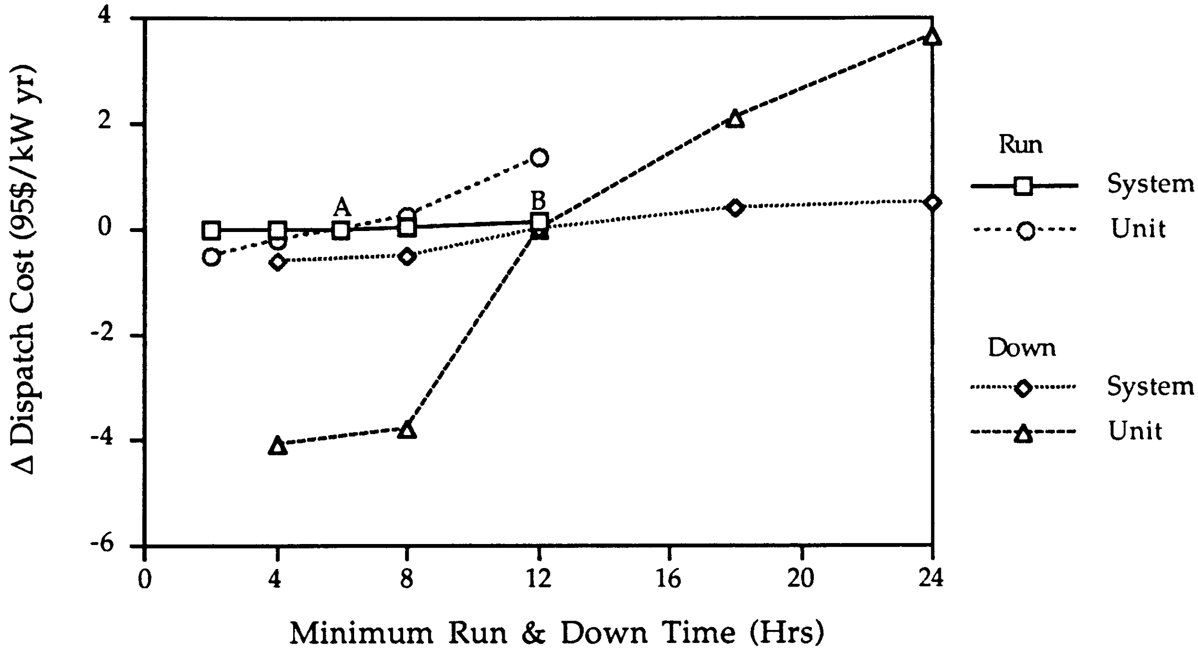
Figure 5.22 - Change in Dispatch Cost as a Function of Dispatch Constraints, Unit 1



For this generic baseload coal fired unit, the base parameters were 12 hours minimum run time and 36 hours minimum down time (points A and B). Varying the minimum run time from 4 hours to 24 hours had no effect on either the total unit or system costs, and the system cost line with the square symbol overlaps the unit cost line with the round symbol which cannot be seen.. Since baseload units rarely shut down, their usual run times obviously exceed even the largest minimum values tried.

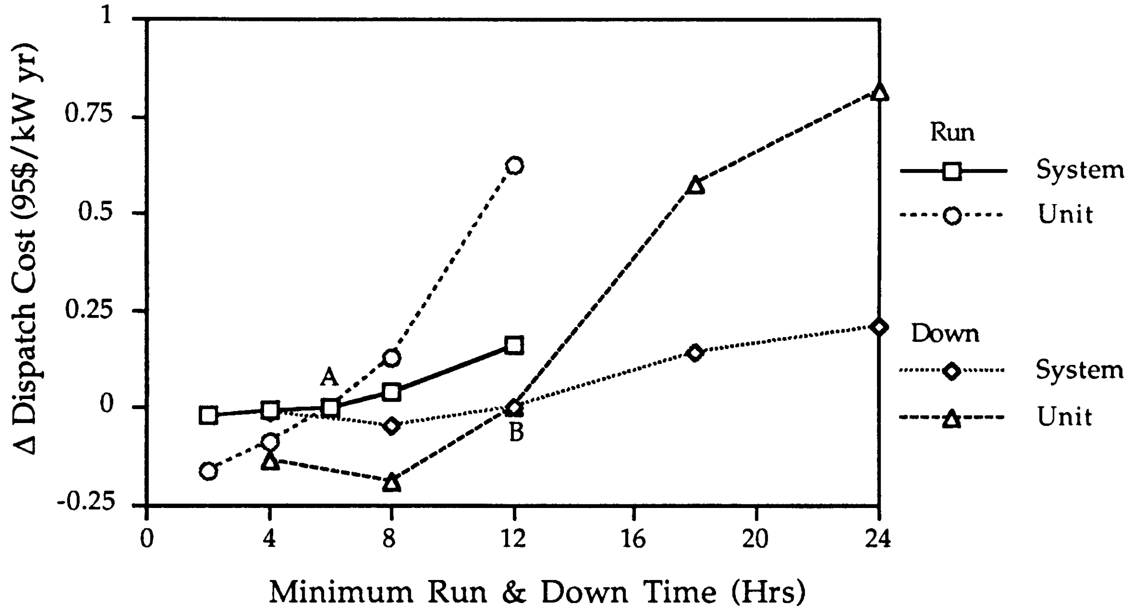
The minimum down time was varied from 6 hours to 48 hours. The single 12 hour increase over the base value had no impact on either unit or system cost, because there are few if any times when it would be desirable to shut down a base load unit and then be limited by the minimum down time. Reducing minimum down time had a benefit of approximately 0.3 $/kW which appears first for the unit cost at the 24 hour level and then for the system cost at the 6 hour level. The impact on system cost is slightly larger than the impact on unit cost, which is counter to intuition and results for the other units. Normally relaxing the dispatch constraints used will reduce the units run time, and this is picked up by a cheaper unit so that system cost drops less than unit cost. In this case it appears reducing the down time allows unit 1 to be shut off and some other unit is dispatched which has a higher cost. As noted in Chapter 4, the Polaris model makes an initial dispatch, refines it for feasibility only by allowing units to run longer, and then optimizes by only by keeping a unit running when this is cheaper than incurring startup costs. This limited optimization means that some seemingly contradictory results may appear, especially when the scale of the results is relatively small, as is the case for units 1 and 5 where the results are small in comparison with units 2, 3 and 4.

Figure 5.23 - Change in Dispatch Cost as a Function of Dispatch Constraints, Unit 2



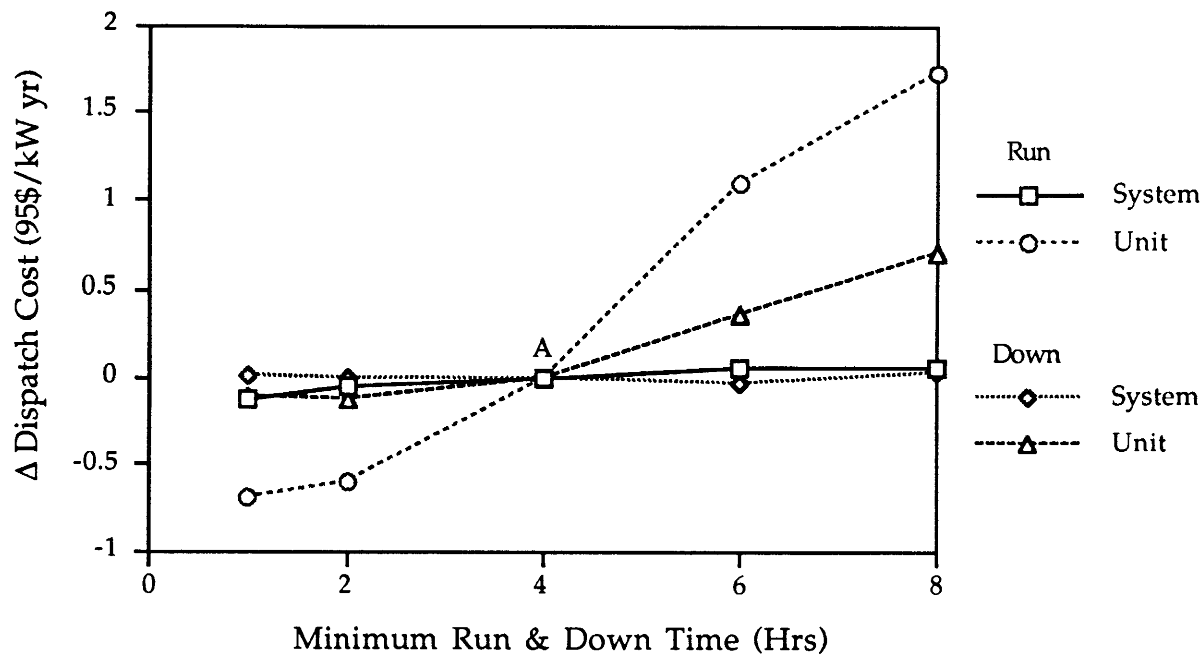
For this large, intermediate load, oil fired unit the impacts of varying the dispatch constraints were the largest of all the generic units modeled. The results were also more consistent than for the other units where the results were smaller. The base parameter levels were 6 hours for minimum run time and 12 hours for minimum down time (points A and B). Relaxing these base constraints decreased unit and system costs and tightening them increased costs, although the effect of the run time constraint on system cost was the lowest impact. The maximum impact was caused by the downtime constraint, with benefits below the base value of 4.14 and 0.61 $/kW for the unit and system costs respectively. Most of the benefit was obtained by reducing the minimum down time from 12 to 8 hours, with a smaller marginal reduction to 4 hours. Increasing the minimum downtime constraint to 24 hours raised the unit and system costs by 3.64 and .489 $/kW respectively in a more linear fashion.

Figure 5.24 - Change in Dispatch Cost as a Function
of Dispatch Constraints, Unit 3



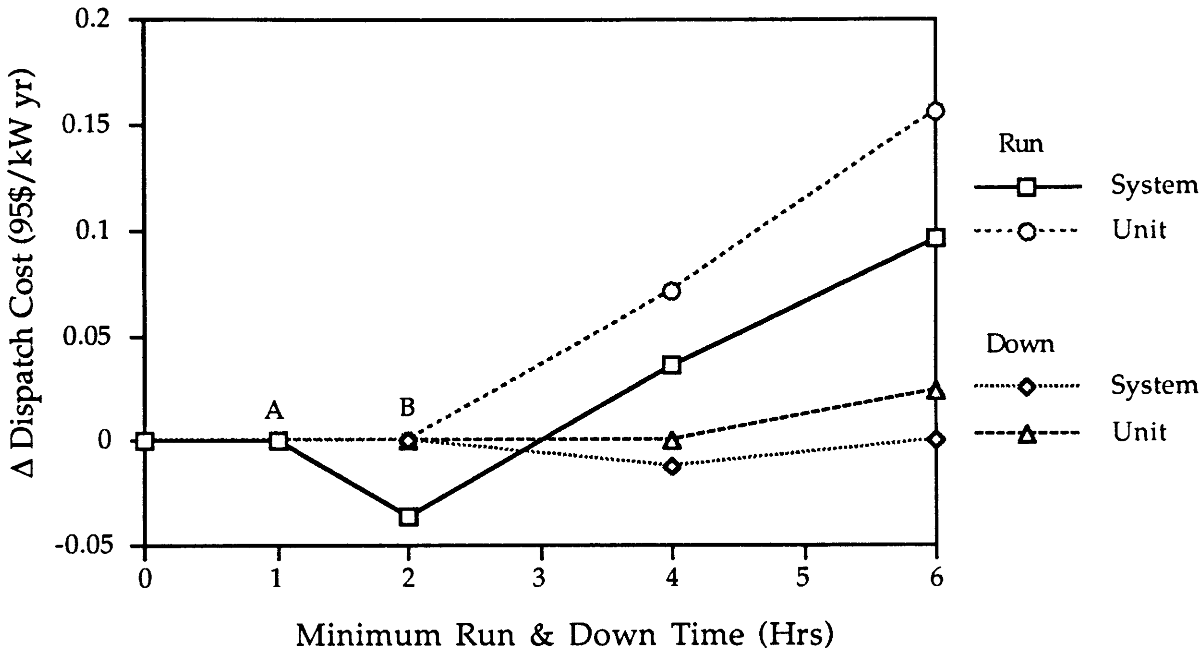
This figure shows the results for generic unit three, which is a large, high intermediate load plant burning number 6 oil. This unit had the third highest impacts, and minimum run and down times of 6 and 12 hours respectively (points A and B). Reducing minimum down time on this unit had a greater impact than reducing minimum run time, with a total variation of 0.8 and 0.2 $/kW respectively over the range of 4 to 24 hours. In this case, the costs for both constraints increase more (and more steeply) as the minimum times increase than they decrease as the minimum times drop. For the minimum down times, both system and unit costs decreased from 12 hours to 8 hours, but increased again slightly from 8 to 4 hours. This follows minimum at 8 hours in the number of hours run for the year by this unit shown in Figure 5.25 below, so there appears to be an non-optimal interaction between startup costs and run costs in Polaris.

Figure 5.25 - Change in Dispatch Cost as a Function of Dispatch Constraints, Unit 4



Generic unit 4 is a mid-range intermediate load combined cycle plant that had the second largest overall variation of costs over the range of dispatch constraints. As mentioned above, this unit had a lower actual dispatch cost than originally thought, which was due to a fuel switch from oil in the EGEAS database to natural gas in the Polaris database. However the range of minimum run and down times considered were both still considered appropriate regardless of the fuel used. Both run and down time constraints varied over a range of 1 to 8 hours with a base value of 4 hours (point A). For this plant the costs of tightening the constraints were again higher than the benefits of reducing them. The run time constraint had the greater impact, with a total variation of 2.41 and 0.18 $/kW for unit and system costs over the range modeled. The variation in system cost over the range of down times modeled was essentially zero.

Figure 5.26 - Change in Dispatch Cost as a Function of Dispatch Constraints, Unit 5



This generic unit was a oil distillate fueled peaking unit with combustion turbine technology. The base minimum run and down times were 0 and 1 hours respectively (points A and B). Because peaking units are very dispatchable it makes sense that reducing them has no benefit, and that costs can only increase as minimum run and down times increase. As with the base load unit, the overall cost variation was very small (0.16 and 0.10 $/kW for unit and system costs), and some unevenness in the graphs was attributed to error.

Another way of looking at the impacts of dispatch constraints is by observing their effects on unit starts per year and unit hours of operation. These results can be significant for calculating the costs and benefits of unit operation which do not depend upon unit dispatch and its interaction with the rest of the system. There are some fixed costs which are incurred at each startup and other variable costs which depend upon the number of hours of operation. The total of these for the year should be compared against the benefit of the increased generation. Also, startup emissions are greater than steady state emissions (as with a car or lawn mower), and these increased emissions have a value which can be set against the component value of dispatch constraints due to higher generation. All this information together should enable plant operators to more rationally optimize the way in which each unit is dispatched.

Figures 5.27 and 5.28 below show these results for startups per year and hours of run-time per year. The range of the results obscures some details in Figures 5.25a and 5.26a, and their scales have been expanded in Figures 5.25b and 5.26b so that the results for some units can be seen in more detail.

Figure 5.27a - Unit Starts as a Function of Dispatch Constraints

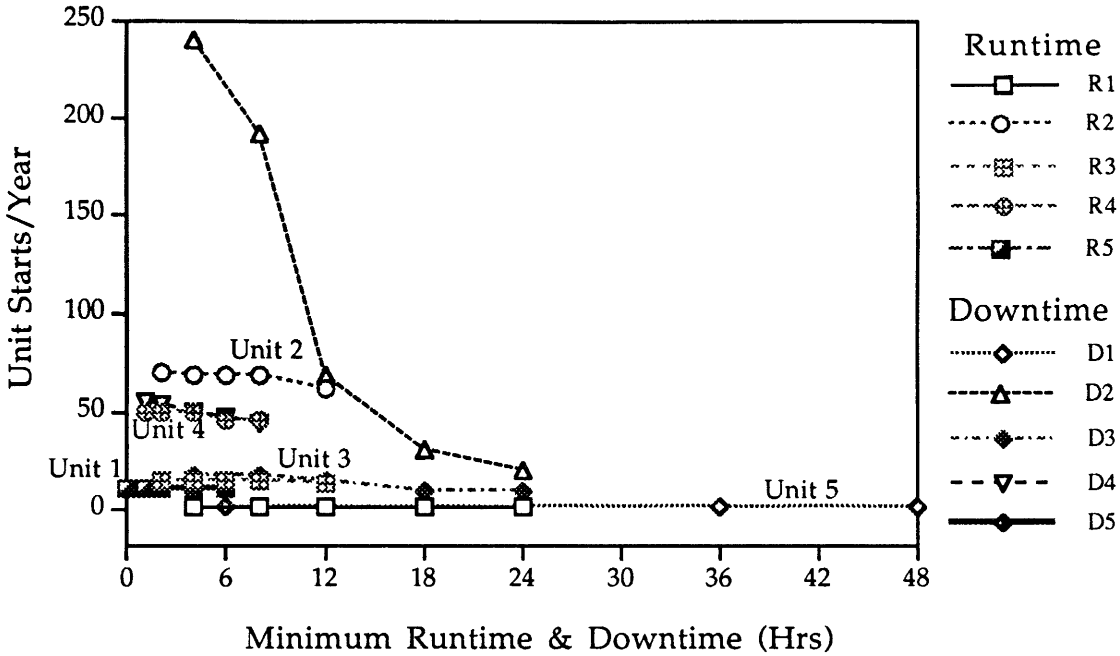


Figure 5.27b - Unit Starts as a Function of Dispatch Constraints

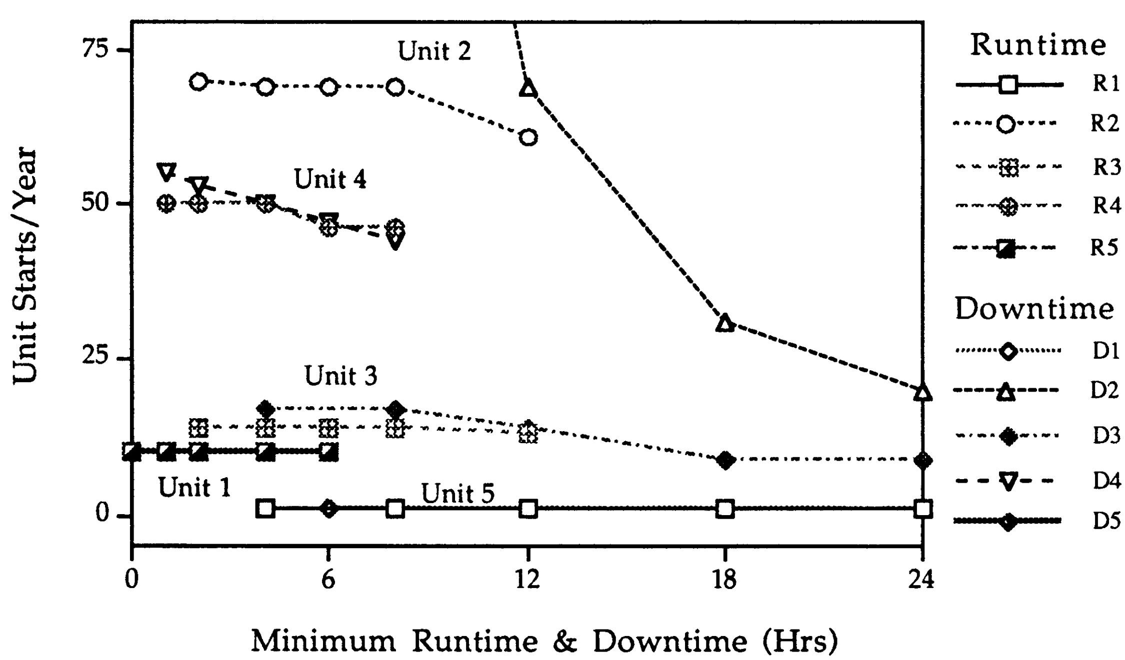


Figure 5.28a - Unit Operation as a Function of Dispatch Constraints

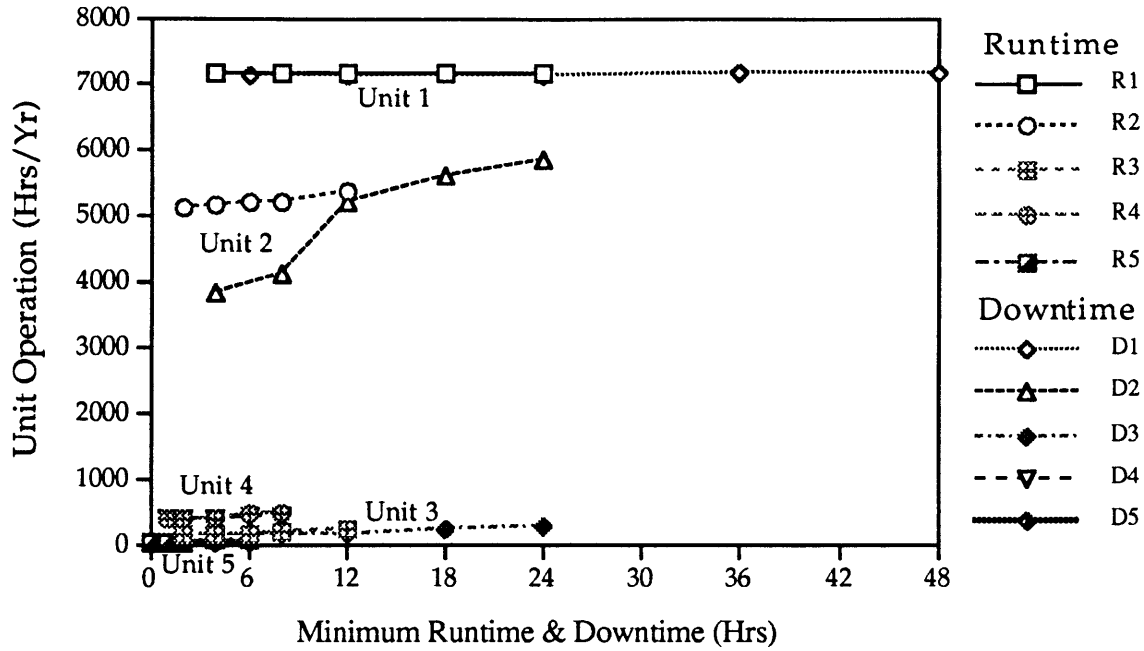
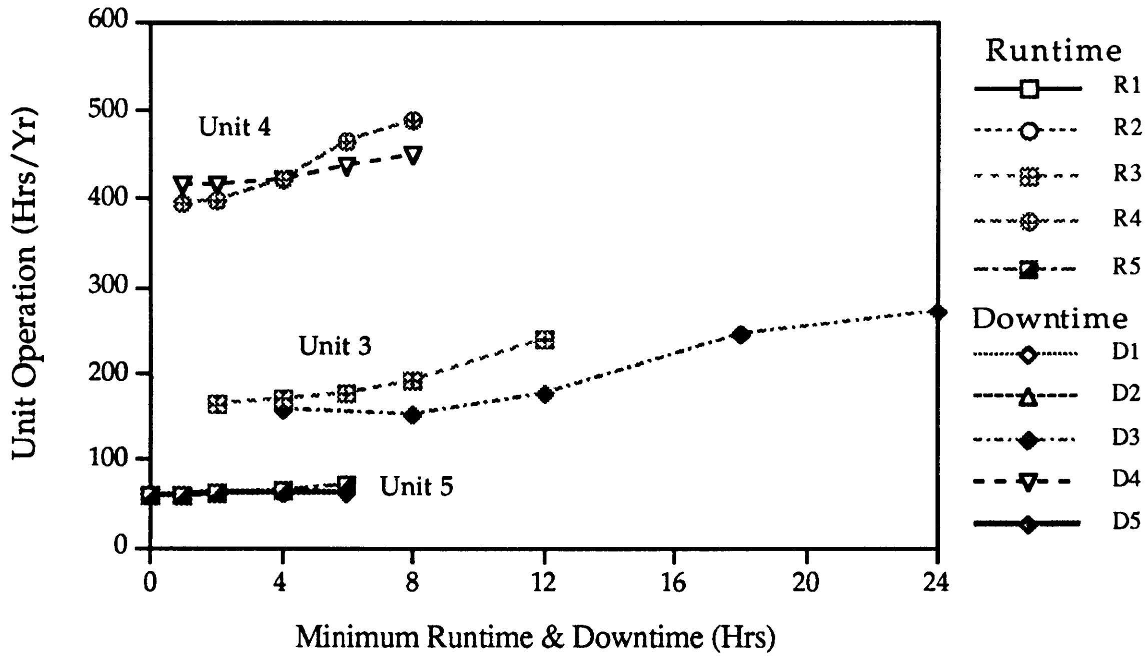


Figure 5.28b - Unit Operation as a Function of Dispatch Constraints



These figures show the results in complementary ways. As expected, the number of hours of operation are in the reverse unit order from the dispatch costs, with the baseload unit having the most hours of operation and the peaking unit having the least. The unit order by number of starts is less obvious. The baseload unit 1 has very few starts, but unit 2 has the highest number and the annual number drops as the dispatch cost rises until the peaking unit has even fewer than the baseload. This makes sense, since units above base load cycle less frequently according to the number of which days reach a peak load requiring them. On both graphs the effect of minimum run time and especially minimum down time is most striking for unit 2, whereas these constraints have less effect for all the other units. Overall, there seems to be a significant correlation between the range of costs shown in Figure 5.21 as a function of the dispatch cost and the annual number of starts shown in Figure 5.27, which makes sense since both cost and startups depend upon the how the unit's position in the dispatch order interacts with the unit's dispatch constraints.

To summarize the results of this section it is possible to draw several general conclusions.

- The results found in this section are the first time that the unit and system effects of existing unit dispatch constraints have been quantified, and may be important for setting the optimum level of dispatch constraints whether in the existing or future competitive market. Under competition, generators and an independent system operator may use this information to set a price on how quickly generating units can respond to dispatch requests.

- The results in this section are not large but are still significant. The maximum 30 year NPV decrease in unit cost was approximately 39 1995$/kW. This is considerably smaller than other component values quantified and discussed in this chapter, but the different sources of value found are not necessarily competitive, and these results may be large enough to affect dispatch for some units.

- Results are highest for large, low intermediate load plants. Based on the marginal cost curve for the NEPOOL system and Figure 5.21, the largest results lie in a variable cost range that roughly corresponds to oil-fired units, from 20 to 35 mills/kWh.

- Results are larger for larger units. The cost/kW results presented above are more general, but they obscure the obvious fact that relaxing constraints on the largest units is most valuable. Unit 2 has an approximate capacity of 600 MW, so varying the minimum down time over the range considered had a total impact of about 4.66 million 1995$ per year on total unit cost.

- The relative effects of the two constraints shift as the overall responsiveness of the unit changes. Minimum down time has a greater impact on results for units 1, 2, and 3, while minimum run time has a greater impact on units 4 and 5.

- System cost reductions do not go up proportionately with unit cost reductions. The gap between these cost effects is largest for unit 2 which had the largest overall results

- Although the range of results is due to the exogenously chosen range of variation chosen for the two constraints, the results with this range are based on historic system data which is relatively certain. The largest source of uncertainty for this component value was judged to be possible inaccuracies in the Polaris model. It was mentioned in Chapter 4 that the dispatch optimization method used by Polaris is a relatively simple one. If a more sophisticated dispatch algorithm were to be used, the results presented above should represent minimum amounts that could be achieved.

The results presented above have been given in $/kW for the single year modeled. In order to include the benefits of dispatchability in the evaluation of a new utility plant, the present value of these benefits over the life of the plant can be calculated by the same present worth factor used for the other results. If unit 2 was new and had an expected life of 30 years, the range of dispatch constraints modeled can have a total net worth of approximately $73 for the plant and $10 for the system as a whole.

It should be remembered that under deregulation the value of dispatch constraints depends upon ones point of view. Increased total unit cost indicates increased unit generation and revenue for the owner, so that there is an incentive for an independent generator to decrease the dispatch constraints. For the overall system the savings per unit are much smaller, but the incentive offered to relax dispatch constraints can be offered to many plants. This points out several uses for the results of this section.

- First, present utility planners and plant operators can compare the value supply curve for the two dispatch constraints modeled here against the current operational, economic, and environmental factors which are currently used to set these constraints. The value of these dispatch constraints has never been calculated before, so plants have been dispatched and operated on the basis of how the unit should operate relative to other generators, and of how faster or more frequent operation would increase maintenance costs and emissions. With this new information, generators will have more economic data to optimize dispatch constraint levels.

- Second , under vertical utility dis-integration, a network dispatcher or coordinator will want the units to set their dispatch constraints based on their system value rather than their unit value. The independent system operator needs to send price signals to the generator based on these constraints so that individual plant operators do not maximize their own operation in a way that is uneconomical from the system's point of view.

- Third, this study has obtained results for individual generating units. For intermediate load plants where this component value exists the benefits should be cumulative as more than one unit change their operation. It will take more study beyond the scope of this thesis to determine whether these benefits are linearly additive or whether and how much their benefit per kW diminishes as more units claim this component value.

5.6 Comparison of Relative Scale for Component Values Modeled

The results discussed in the preceding sections have been presented both as the annual value for 1995 and as the net present value of 30 years of future benefits. This section compares the relative scale of the five sample component values analyzed, as shown below in Table 5.5. This table shows mostly benefits per kW averaged over the ranges described in parentheses. The three exceptions are that the value of reducing reserve margin through nuclear unit elimination is negative (a net cost), the value of storage for NDT generation is given in terms of $/MWh, and the value of thermal unit constraints is given as the maximum range of impact across the units and parameters modeled.

Table 5.5 - Relative Scale of Component Values Modeled

	1995	30 Yr. NPV
Reserve Margin	($/kW/yr)	($/kW)
Proportional Reduction	96.6	911
(Average for 30% to 5% RM reduction)		
Nuclear Reduction	-42.5	-401
(Average for 7 LWR reduction)		
Unit Size	($/kW/yr)	($/kW)
(Average for 8x size reduction, 1360->170 MW)	38.35	362
NDT Dispatchability	($/MWh/yr)	($/MWh)
Storage Capacity, PV	542	5109
Storage Capacity, Wind	933	8795
(Average over 100% storage capacity, and inverter capacity from 50->200%)		
	($/kW/yr)	($/kW)
Inverter Capacity, PV	10.14	95.6
Inverter Capacity, Wind	6.02	56.8
(25->50% inverter capacity, average over storage capacity from 40->100%)		
Spinning Reserve	($/kW/yr)	($/kW)
(Average from 50% to 150% SR)	15.81	149
Thermal Dispatch Constraints	($/kW/yr)	($/kW)
System Cost	1.10	10.4
Unit Cost	7.78	73.3
(Over range for low intermediate load unit)		

In general, the size of the benefits above depend upon the range of parameters that were varied for each section. The component values for reserve margin (fractional reduction), unit size, and spinning reserve were roughly uniform over the range of variables studied, so that the marginal values per kW were approximately equal to the average over the entire range. For the value of NDT dispatchability, the marginal values of storage and inverter capacity were initially very high and then decreased. Since the optimization of NDT dispatch depends upon the interaction of both storage and inverter capacity, the marginal value for a single variable can be misleading. In this case, the averages shown above were taken where they were significant along one axis and relatively consistent along the other. Finally, the thermal dispatch constraint was most dependent not only upon the range of parameters chosen (minimum run and down times), but also upon the marginal cost of the generation unit studied.

5.7 Sample Application of Component Values to Specific Utility Options

In order to tie together the theory of Chapters 2 and 3, and the analysis and results of Chapters 4 and 5, it may be useful to consider the example of three different utility options. The first option is an MHTGR, considered for use in low intermediate load service, the second option is solar PV generation with storage, and the third is a DSM dispatch option based on an air liquefaction plant. Each of these examples is reviewed for the range of component values which it can supply, and each of these component values is discussed, including whether it is generic or specific and whether it has been quantified in this thesis.

MHTGR - Like other nuclear reactors, the MHTGR has a high capital cost (1800 94$/kW for 4 units) and a low variable dispatch cost (11 94$/MWh) which require a high capacity factor for it to be competitive. The MHTGR has a higher variable cost than PWRs and the ALWR (10.3 v. 5 to 6 94$/MWh), but its capacity factor is high enough (approximately 90% availability) to be competitive with conventional coal power plants in some design studies and using certain fuel price forecasts[44] . This thesis has addressed how the advantage of smaller size could make the MHTGR more competitive with the ALWR. The question is, are there more component values which the MHTGR can claim which would help to make the MHTGR competitive with other base or intermediate load technologies? For the sake of comparison, a range of available base load coal-fired technologies were reviewed using the EPRI Technology Assessment Guide. These units ranged in size from 200 to 500 MW with capital costs of approximately 1340 to to 2120 94 $/kW. An

[44] ABB/Combustion Engineering, Inc., Bechtel National, Inc., Gas-Cooled Reactor Associates, General Atomics, Oak Ridge National Laboratory, and Stone & Webster Engineering Corp., *Modular High Temperature Gas-Cooled Reactor Commercialization and Generation Cost Estimates*, DOE-HTGR-90365, issued by Gas-Cooled Reactor Associates, September 1993..

advanced pulverized coal (APC) design was chosen with a size of 300 MW and capital costs of 1746 94$/kW with AFUDC for comparison. Review of the MHTGR indicates that the following seven component values may apply.

1) Size - The value of reducing unit size is related to the amount of size reduction possible and the capital intensivity of the technology. The cost of four 170 MW MHTGRs built at once is 1800 94$/kW overnight. By interpolating from the results presented in Figure 5.8 it can be seen that reducing the effective size of an MHTGR plant from 680 MW to the 300 MW of an APC unit would reduce the NPV system cost by 136.8 million 95$, or 201.2 95$/kW. Since the results from the EGEAS model include interest during construction, this value can be subtracted from the MHTGR cost of 2068 94$/kW which includes AFUDC. This means that approximately 60% of the MHTGR's cost premium over the APC can be cut by building it in 'units' of 300 MW rather than 680 MW at a time..

2) Reserve Margin - Reserve margin is necessary to allow for planned maintenance and unplanned forced outages. Units that have a high availability have less need for reserve margin. The MHTGR has an availability of 89% compared to 84% for the APC, which means that for a unit size of 300 MW, the APC will require on average 15 MW more reserve capacity. From Section 5.1 above, the net present value of reducing reserve margin while maintaining similar system composition is 911 $/kW, so the MHTGR will deserve a comparative credit of 13.67 million 95$, or a net reduction of 45.6 95$/kW.

3) Spinning Reserve - The MHTGR has a very fast response time for power changes so it can be used for spinning reserve, but unless there is sufficient baseload capacity that the unit is used for intermediate load it will never be available for spinning reserve. Therefore, although this component value is theoretically available, for the present case it remains zero.

4) Dispatchability - The fast response time of the MHTGR means that it does not have the same dispatch constraints as a coal fired unit. However the results from Section 5.5 above show that unless there is

sufficient excess capacity that the MHTGR is used for intermediate load, this dispatchability will not have any value.

5) Fuel Risk - The cost of nuclear fuel is a small fraction of overall MHTGR costs, so this technology has a relatively low fuel risk. This relative advantage is best analyzed by applying an appropriate risk premium to each fuel. This financial risk component value has not been analyzed in this thesis, but as discussed Chapter 3 there are several possible analytic tools for evaluating this risk.

6) Capital Cost Risk - The MHTGR is not a new nuclear technology, but the direct Rankine cycle design discussed in this thesis is new. Even with demonstrated inherent safety during a loss of coolant accident, public attitudes about nuclear reactors will likely lead to opposition that may exacerbate the cost risk of a capital intensive new technology. Modularity, short lead times, and standardized design will reduce this risk, so that the capital cost risks of existing PWRs will not be directly comparable. This risk has not been quantified in this thesis, but would deserve considerable attention.

7) Environmental Emissions - Although spent fuel is an environmental concern, the cost of its disposal will be covered by the current generation surcharge and any costs of environmental externalities are so uncertain and so far in the future that their discounted present value is hard to determine. However, the MHTGR does have an advantage in its lack of emissions and solid waste from scrubbers. This comparative advantage is best analyzed by charging each competing technology for the cost of its emissions, rather than giving the MHTGR a credit. The most defensible cost for such emissions appears to be the marginal cost for the most efficient strategy that will reduce total system emissions to their mandated levels.

All the component values listed above are generic, rather than specific to any particular network location. This thesis has demonstrated methods for calculating component values 1 through 4 listed above, which together give a total NPV benefit of 247 95$/kW, compared to the capital cost difference between the MHTGR and APC of 322 94$/kW. The MHTGR already has a higher capacity factor and lower fuel cost than the APC, so the additional component values should make the MHTGR much more competitive on a levelized cost basis. The fuel risk and environmental benefit component values further favor the MHTGR over the APC, but technological uncertainty and political opposition may be determining unless demonstration unit(s) and NRC design approval reduce the capital cost risk.

Solar PV - As a distributed, non-dispatchable energy resource, solar photovoltaic generation can claim a different set of component values. These include the following

1) Dispatchability - The addition of storage and inverter capacity can make solar and wind generation effectively dispatchable and gain a component value credit based on shifting generation to more valuable hours with higher spot prices. To show the use of the value supply curves shown in Figure 5.11, assume that PV generation is built using storage equal to 30% of the annual peak day's generation and inverter capacity equal to 50% PV capacity after losses. Choosing the 50% inverter capacity curve and interpolating along the storage capacity curve shows that the annual value of PV generation with and without storage is 19.1 and 22.2 million 95$ per year respectively for 1000 MW of PV capacity, indicating net annual and net present component values of 2.1 $/kW and 19.8/kW respectively. Note that these values are per kW of overall PV capacity, and differes from the results presented above which were based on storage and inverter capacity.

2) Generic T&D Credits - Distributed generation will avoid thermal transmission losses and some distribution losses, based on the exact siting. Thermal losses are higher at peak hours, so by shifting distributed generation to these hours the avoided losses are slightly higher (approximately 10%) than average thermal T&D losses . These avoided losses can be used reduce the size of an equivalent distributed generation option by 10%, or to give it a cost credit of 11%. In addition, distributed generation will avoid the average NPV cost for new T&D capacity, which is estimated to be 857 $/kW per kW of existing generation. This large average value will only be available if PV generation is widely distributed across the network below the

distribution level and in large enough quantities that significant amounts of new T&D construction is avoided, but nevertheless it illustrates the large benefit which may be available.

3) SpecificT&D Credits - In addition to the average T&D benefits just described, distributed generation in specific locations may have specific aT&D component value based on reduced maintenance, replacement, and new T&D capacity requirements. This value will require site specific study and may make the total T&D credit either higher or lower than the average value of 857 $/kW given in 2) above.

4) Reliability - The addition of storage capacity to distributed generation produces a reliability benefit by reducing stress on the network and providing local power if transmission or distribution lines fail. The value of this incremental reliability depends upon both network location and customer needs, and thus requires specific evaluation.

5) Fuel Risk - Because solar generation requires no fuel, it will receive a relative advantage when a risk premium based on the price volatility of other fuel is added to other generation options.

6) Capital Cost Risk - Although the capital costs of PV generation are high, the capital risk is not. This is based on small unit size and short lead times which produce flexible capacity additions for following load growth, and the low risk of cost overruns based on technical problems or safety concerns. If capital cost risks are applied uniformly to competing utility options, solar generation will gain a relative advantage from this component value.

7) Environmental Emissions - PV generation has clear environmental advantages with no emissions, and only possible fabrication impacts and recycling inefficiencies if battery storage is used. As with the financial risk benefits of 5) and 6), PV will receive a relative benefit when the environmental costs are added to competing options.

All of these seven component values are generic, except for the specific T&D and reliability values which are related to network location. The five 1) and 2) can be added together to produce a net credit for PV generation, while

5), 6) and 7) are effectively zero and will produce a relative credit when the appropriate costs are charged to competing options.

Dispatchable DSM Options - In comparison with the two generation options discussed above, a DSM option can offer some component value benefits by scheduling consumption and reducing the transmission and distribution capacity necessary to serve it. An air liquefaction plant is an excellent example of such an option, because electricity is the major expense in production and the consumption can be readily controlled and rescheduled. This DSM option has the following component values.

1) Spinning Reserve - If load can be reduced quickly enough, then customers can compete with generators in supplying spinning reserve. This service can be controlled either by the customer or directly by the utility. The value to the customer of supplying this ancillary service depends upon when the load is scheduled and its correlation to system load which determines the marginal cost of spinning reserve supplied by generators. Because an air liquefaction plant will schedule its consumption at hours when the spot price is low, the value of spinning reserve which it can supply will be less than the average value of the overall level of spinning reserve which was determined in Section 5.4 above. Further analysis to find this value would be worthwhile, but under a competitive market it will be determined by bids from both generators and consumers.

2) Load Dispatchability - Just as a solar PV plant can dispatch its generation by the addition of storage and inverter capacity, an air liquefaction plant can schedule its production by the addition of both storage capacity and excess production capacity. Production capacity can be gained either by increasing the designed size of the compressors and liquefiers, or by reducing the target level of production. By producing liquid air when the marginal system cost (spot price) of electricity is low, the total cost of production can be reduced. As discussed in Chapter 4, a storage optimization algorithm for this application was developed by

Daryanian[45], analogous to the NDT generation storage algorithm developed for this thesis. This prior work reports average annual savings of 10.5% of total electricity cost, based on analysis of one representative day for each of the four seasons. The analysis used spot prices from the PJM power pool, an 18% non-cyclable compressor load, and a load factor of 75% (equivalent to excess capacity of 33%). Storage was not reported to be a signficant constraint, and sensitivity analysis produced savings dependence upon storage and production capacity which can be called value supply curves in the context of this thesis. Combined with the costs of storage and production capacity, these curves can be used to determine the optimum amount of these variables.

3) T&D Credit - By operating at off peak hours, a dispatchable load will reduce peak load stresses upon the transmission and distribution system. This reduced stress can produce a component value credit by reducing necessary maintenance or deferring the replacement of old T&D capacity or the construction of new T&D capital. An air liquefaction plant is a large enough load that it will generally be connected directly to the system at the transmission level, so any distribution benefits will not apply. Because this is a component value which is specific to network location it is not evaluated in this generic example, but the cost of upgrading or building new transmission lines means that it can be very substantial if the system is stressed near its limits at the location in question.

The results of this chapter are representative examples of component values which are generic (or system wide). These results show that there can be very significant value in unit/system interactions and in system wide analysis which have not been used in the prior, conventional analysis of limited, generation options. There is reason to believe that the other component values discussed in Chapter 3 and above for three specific utility options may be equally significant, especially in certain places for values which are specific to network location.

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[45] Daryanian, B., *The Definition and Application of an Optimal Response Algorithm for Electricity Consumers and Small Power Producers Subject to Spot Prices*, S.M. Thesis, Technology and Policy Program, Mechanical Engineering Department, MIT, 1986.

6.0 Conclusions

Electric utility planning is a complex and important problem based on the size, complexity and importance of the electric utility sector. The utility industry has undergone rapid change in the last 20 years, which is only accelerating with the present advent of deregulation, competition, and industry dis-integration. Utility planning has evolved along with the industry to include demand side options, independent power producers, open bidding, spot pricing, emissions controls and trading, and integrated resource or least cost utility planning. Nevertheless, the basic paradigm for utility planning has remained regulatory hearing approval based on the lowest average or levelized cost of technological options added to the utility system. This paradigm produces a number of planning problems, including a limited choice of options, a focus on options alone without consideration of how they interact with the system, and the neglect of significant sources of value. These sources of value include system dispatch, transmission and distribution, reliability, and financial risk. Current industry trends mean that these values which have been only implicitly or unevenly included in utility planning may now have real market value, enabling unbundled services to be priced or a wider range of options to be compared on a more even basis.

This thesis discusses a new methodology for finding and quantifying new sources of value in the utility planning process, in order to address the problems mentioned above. The nature and deficiencies of the planning process are discussed in Chapter 1, which then outlines the approach of the rest of the thesis. Chapter 2 discusses the theoretical underpinnings of the thesis methodology. It outlines a new framework for comprehensive identification of both utility options and sources of value, based on the chain of utility functions and the time frames relevant to different aspects of utility construction and operation. Once these sources or components of value have been identified, this thesis proposes a new methodology for generic analysis of these values separate from the options which possess them, based on a subset of relevant option and system characteristics. This methodology is extended by the new concept of producing supply curves for these component values by parametric variation of one or more of the related option or system characteristics. Chapter 3 discusses individual component values identified, five of which were selected as examples to demonstrate the methodology quantitatively. Chapter 4 discusses the data and modeling assumptions used in the analysis of the five component value examples, including a new and original storage optimization algorithm. Chapter 5 discusses the results of the analysis for these five component values, compares them on a common basis, and presents examples of full value analysis for three utility options. This chapter presents the general and specific conclusions of the analysis.

6.1 General Conclusions

Based on the research and analysis results, this thesis draws the following general conclusions.

1) Current planning practices have serious deficiencies. These include a focus on individual technological options rather than the full range of utility options or option/system interactions, and on average or levelized pricing that does not include the full range of component values available to utilities. Planning practices are dictated by utility regulations which vary significantly between states. The onset of competitive deregulation will eliminate most of these regulations, and create the opportunity and necessity for new types of private planning and public regulation which can benefit from the methodology of this thesis.

2) Many of these deficiencies can be remedied by incorporating new sources of value in utility operation and construction. These component values can be related to system dispatch, transmission and distribution, reliability and quality of service, financial risk, and environmental costs. It is obvious that values related to these categories exist, but to date they have been given limited and uneven recognition and application related to specific technologies such as photovoltaics.

3) The framework outlined by this thesis provides a new and comprehensive way of searching for and identifying both new options and new component values, based upon the sequential progression of

utility functions and the time scales associated with different aspects of utility planning and operation.

4) The specific component values identified can be separated from specific individual options that may provide them. The values identified depend upon certain sets of option and system characteristics, and can be calculated from these characteristics without considering a particular technology. Values which are based systemwide characteristics are generic and can be applied to all options, while those values which depend upon site specific system characteristics are specific and can only be applied to options at that site.

5) The component value identified can be quantified using a variety of appropriate models, including hourly and load duration curve production cost models. Chapters 4 and 5 discuss the analysis and quantitative results of five generic component values which have not been calculated before. Specific conclusions for these sample component values are presented further below.

6) Parametric analysis of the relevant option and/or system characteristics can be used to establish the cost or benefit associated with variable amounts of each component value. By varying one or more of the characteristics, a response curve or surface can be mapped out, which can replace future calculations with interpolation. These supply curves can be used to optimize the size or amount of a single option, or be used to apply the component value to many individual options without specific calculations.

7) The component values calculated can be of significant size. The generic values analyzed in this thesis range from approximately -400 to 900 $/kW NPV over a 30 year period. One value was found on an energy basis, with a marginal value of dispatchability approximately equal to 8800 $/MWh of battery storage capacity for a 30 year period.

8) Component values which are specific to certain system circumstances or network locations may be as large or larger than the generic values calculated in this thesis. This conclusion is based in part on the

average size of some component values like transmission and distribution costs (i.e. approximately 40% overall system capital costs), because when an average cost is this large then in some specific instances it must be considerably above average. This indicates that there is considerable incentive for further investigation of specific component values, including network dependent values associated with transmission and distribution, reliability and quality.

9) The component values identified and discussed have value both under both current utility structure and under competitive deregulation and utility disintegration. These values may be ignored or only implicitly considered by current planning aimed at regulatory approval. Under deregulation, some values will automatically be used by players planning based on market incentives, but others (such as spinning reserve or transmission costs) will require unbundling and a market created so that they can be bought and sold and a market prices established.

10) It is not necessary to use all the component values discussed or quantified to create a perfectly level playing field for competing options, but adding any or all of the component values to the current average or levelized cost basis will be an improvement. The examples presented in Section 5.7 show that the component values demonstrated in this thesis can apply to a range of utility options, and that full value estimation can make a difference in the comparison of different utility options.

6.2 Conclusions for Subset of Example Values

In addition to the general conclusions drawn above, it is also possible to draw some specific conclusions from the results for the set of c omponent values analyzed as examples of the thesis methodology. These conclusions include the following.

1) Reserve Margin - Capital investment in generation is expensive, with NEPOOL's 1995 capital recovery costs equal to $6.06 billion. NEPOOL

reserve margins are high compared to historical levels for the country as a whole, and this reserve margin can be very expensive. The value of reserve margin depends upon the composition of the system which has a lower reserve margin. This analysis has shown that reducing reserve margin while keeping system composition proportionally the same can save approximately 100 $/kW in 1995 and approximately 900 95$/kW over a 30 year period. However, if system reserve margin is reduced by not building baseload units (such as the NEPOOL nuclear units considered), then fuel costs will exceed capital cost savings and costs can increase by as much as 43 $/kW in 1995 or approximately 400 95$/kW over a 30 year period.

2) Unit Size - When unit capital costs are high and unit size is large compared to total system load growth, smaller unit size can defer capital expenditures and reduce NPV capital costs. This section has compared the Modular High Temperature Gas Reactor (MHTGR) to the Advanced Light Water Reactor (ALWR), using the modularity to reduce the effective MHTGR size from 1360 MW(equal to the ALWR) to 680 MW, 340 MW and finally to 170 MW, by building 8 units once, 4 units 4 years apart, 2 units 2 years apart, and one unit per year for 8 years. The results of this analysis indicate that capital cost savings exceed increases in system fuel costs, producing an average size related savings of 365 $/kW. This savings reduces the effective capital cost for the MHTGR when it is compared to the ALWR from 1800 $/kW to 1435 $/kW, indicating that the ALWR would be preferred only if its price was below 1435 $/kW.

3) NDT Dispatchability - Non-dispatchable technologies like wind and solar PV generation possess value based on the time correlation of their energy resource with marginal system costs (spot prices). By adding energy storage between the NDT generation and the system load a variable amount of dipatchability can be produced to improve this value. This value depends both upon the amount of storage, and upon the amount of solid-state inverter capacity available for generation from storage. A new algorithm was created to optimize NDT storage based on these two variables. Results show that the initial

value of wind energy is approximately 16 $/MWh v. 22 $/MWh for solar based on their resource patterns over time. The maximum benefits of storage capacity for both wind and PV generation are reached at 40% of the maximum day's generation for the year 1995. The average NPV benefit of increasing storage from 0% to 40% is 1162 95$/MWh for PV and 2311 95$/MWh for wind. The maximum benefits of inverter capacity are generally reached by 50% of total generation capacity for both wind and solar. The marginal benefit of inverter capacity from 25% (the lowest used) to 50% is 95.6 95$/kW for PV and 56.7 95$/kW for wind.

4) Spinning Reserve - Spinning reserve is generator capacity (or interruptible load) available to meet emergency needs on short notice, given as a percentage of the largest unit in service or just in MW. This value depends upon the level of spinning reserve standard maintained. NEPOOL operates at about the 50% level recommended by NERC, rather the the higher 150% level called for by NEPOOL Operating Procedure 7 . Based on hourly modeling by Polaris, the difference in total annual NEPOOL system costs associated with these two levels is $19.8 million. Given the largest baseload unit size of 1253 MW, this is equivalent to an annual reduction of 15.8 $/kW or an NPV savings of 149 $/kW. Although this is not the largest component value calculated, it is still significant. By operating at the lower NERC level, NEPOOL has already reaped this benefit, but under deregulation spinning reserve will be unbundled as one of several ancillary services, and this component value will serve as the basis of a real market value.

5) Thermal Unit Dispatch Constraints - Thermal generation units are limited in how quickly they can be started and stopped. This section evaluated the value of the dispatch constraints provided by minimum startup and minimum run times. These constraints have been provided by plant operators to system dispatchers in the past based on technical limits, environmental emissions and other considerations, but they have not been based on their economic impact on system dispatch costs. Using the hourly Polaris model, minimum run times

and and down times were varied for five different generation units covering a range of dispatch costs from baseload to peaking. The results of this analysis show that the value of dispatch constraints is most dependent upon dispatch cost, with the only significant value occurring for intermediate units. Results depend upon how widely the constraints were varied, but within the limits chosen the largest change in total unit dispatch cost was approximately 8 $/kW. Changing dispatch constraints on a single unit affects the dispatch of similar units, so the total system impact is significantly lower, with a total maximum range of approximately 2 $/kW. This was the smallest component value found, but it provides important new data for setting dispatch constraints. Due to limitations of the Polaris model in dispatch optimization, the actual value of dispatch constraints may be somewhat higher. The impacts of improved optimization and investigating the additivity of changing more than one set of unit constraints at a time are possible topics for further research.

6.3 Overall Conclusions

Utility planning is a complex and important subject with significant problems under both current and prospective industry structures. This thesis presents a new methodology for finding and evaluating new sources of value and applying them to a wide range of utlility options. The results of this thesis indicate that the five component values investigated to demonstrate this methodology produce results which range from small to very large, and it is reasonable to assume that some of the component values discussed but not analyzed may be equally large. These results indicate that the thesis methodology represents a significant improvement when added to conventional existing planning methods which are fundamentally based on average or levelized technology costs alone.

APPENDIX 1

1.0 A Historical Perspective of Value of Service

In order to look at the question of the value of electrical service in electric utility planning, it is useful to have a historical perspective on the technical and regulatory ways in which both value and planning practices have evolved. This appendix addresses this evolution from the early history of electric utility service, and in so doing addresses the context and inadequacies of current electric utility planning practices.

The value of electricity, like any other value, is not inherent in the thing itself but instead created by the estimation of people who need or desire it. For a good or service in an economic market, this need or desire is expressed by a willingness to pay. Electricity is a secondary good which is not consumed directly, but rather provides a wide variety of services which people value differently. The value of electricity depends upon the value of these services. Each customer may place a different value on electricity because the portfolio of services provided by electricity varies between customers, and because customers have different needs for these services. A customer will be willing to pay much for some electrical services and less for others, depending upon the value of goods or services created and the prices of competing sources of energy services. This creates a demand curve for each customer, and in aggregate a demand curve for the electric utility market.

Competition in the electric utility market has always existed, but under monopoly regulation it has been limited. The traditional view has been that the natural monopoly of transmission and distribution led to utility regulation, and in turn the historic price has been set to provide a fixed rate of return to the utilities. Since electricity has been a monopoly good, utilities and customers have focused on the regulated price of electricity rather than its value. Price levels have been expressed through rate structures (flat and declining block rates) that have not reflected a utility's marginal cost curve, but overall prices have still determined how electricity has competed with other sources of energy services, and hence the total demand for electricity. Because of the regulated obligation to serve all customers, generation capacity has been added to the rate base to meet this demand. Economies of scale led for a long time to declining prices and steady load growth. Diseconomies of scale came not from additional generation, but from extending transmission and distribution lines from urban centers to more distant rural customers, and this extension was due to the regulated obligation to serve and governmental policy rather than strictly economic incentives. While the laws of supply and demand have never been repealed in the electricity market, demand curves and supply curves have shifted over the long term rather than through direct, short term competition.

1.1 Historical Evolution of Electrical Services

As discussed in Chapter 2, a comprehensive theory of value for utility planning will incorporate willingness to pay all along the chain of production functions shown in Figure 2.1, for each of the multiple attributes of inputs and outputs at each step. Recognizing this, it is useful to review how the value of electrical service has evolved over the relatively short history of the electric utility industry. In brief, this history is a story of how an expanding range of electric utility services have made electricity more valuable, while increased productivity produced declining real prices until the recent past.

Electrical technology progressed slowly from the early through the mid-1800's, with the development of batteries, dynamos (generators), and electric motors, but actual use of these novelties was rare. The first practical electrical applications included time clocks and security alarms, and arc lighting for theaters, fairs and exhibitions. It was Thomas Edison who demonstrated the incandescent light in 1879, and created the first integrated electric utility that tied together all the elements of generation, distribution, and end-use (lighting) technology in 1882 with the opening of the Pearl St. station in New York City[46].

With the start of public and private generation, the order in which new electrical technologies penetrated the market reveals much about their end-

[46] Nye, David E., *Electrifying America, Social Meanings of a New Technology, 1880-1940*, p. 30, MIT Press, Cambridge MA, 1991.

use values and the way in which the public chose them based on not just cost but their other advantages as well. Electrification in the US covered the period from 1880 to 1945. The major areas of electrical use in order of their adoption were public and industrial lighting, electrical streetcar transportation, industrial motor drives, urban residential service, and rural farm service. As with the development of any technology, the path of development was a complex interaction between the technical possibilities and the society which adopted them. Adoption must follow development, but the perceived value of particular services is the spur to that development. This process is not solely and objectively rational; fashion and preference play major roles in choosing between the technological possibilities.

Public lighting began in the 1880's, starting with street lighting, and progressed to theaters, hotels, department stores, clubs, and the private homes of the rich. It was promoted by a series of world's fairs and exhibitions from 1894 to 1910, and was adopted for prestige and status as well as for its practical advantages. In urban areas its chief competition was natural gas. Lighting is an excellent example of how value can result from many end-use technology characteristics, because electric lights were brighter, had better color balance, produced no soot, water vapor or acid fumes, and were much safer because of the reduced fire hazard. Electric streetlights were immune to blowouts from the wind and could be switched on together without requiring lamplighters. Edison recognized from the start the importance of selling light as opposed to electricity, and installed wiring and fixtures as well as creating the generator and distribution system. Initial service was unmetered and billed based on the number of bulbs. Edison's stated goal was to "make electric light so cheap that only the rich will be able to burn candles[47]."

Electric streetcars or trolleys succeeded horse drawn streetcars starting in 1888, and served from the 1890's through the 1930's when they were largely replaced by the automobile except in some densely populated cities. These streetcars used individual motors powered by overhead wires. Besides being cheaper than horses, they were cleaner, faster and more sanitary. These streetcars led to the development of subways and were often linked to them (Boston had the first subway in the US in 1897). Interurban service followed

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[47] McDonald, Forrest, *Insull*, p. 20, University of Chicago Press, Chicago, 1962.

in-town service, and survived it for a short period. So called traction companies also supplied electricity to customers along their tracks, competing with private and municipal utilities. Many companies built amusement parks at rail terminuses to provide complementary loads and raise load factors, and some interurban lines provided the first rural electrification to a limited number of farms. Streetcars had large impacts on the social structure, linking cities and suburbs for commuting, shopping, recreation and entertainment, and light freight delivery.

Electrical lighting in factories was common before 1900, but electric motor drive penetrated the industrial market gradually from approximately 1900 to 1930. Electric motor drive replaced water or steam driven belts and pulleys first as the prime mover for the pulley system, next powering groups of machines and finally powering individual machines. In addition to cost, electrical drive had many other advantages, including plant siting (away from rivers), plant layout and process design, and product quality. Although the safety risks of electrical shocks were introduced, the mechanical hazards of exposed belts and pulleys were reduced or eliminated. Factory electrification also included materials handling and transportation through cranes and hoists, conveyor belts, and the assembly line. Electrical ovens replaced fossil fuels due to even, constant, clean and controllable heat for drying, baking, roasting, tempering, and heat treating.

As in industry, the first electrical service provided to urban homes was lighting, with the first penetration into this market from approximately 1910 to 1915. The penetration of labor saving appliances was not prevalent until after World War I, and the majority of urban homes were connected to utility service in the decade following the war. The first appliances were electric irons, vacuums, washing machines and fans, followed by other small appliances, stoves, and finally refrigerators. These appliances were not only cleaner than their predecessors, but also reduced labor and provided better service. Radio was entirely new, and had a strong penetration from the early 1920s. Utilities conducted promotional campaigns to increase appliance purchases and load growth, focusing on the services electricity could provide.

Rural electrification did not occur until the period of approximately 1935 to 1945. Unlike Europe, private US utilities were extremely reluctant to invest in rural distribution systems. It was not until 1935 that the Rural Electrification Administration was created as part of the New Deal, and in 1936 legislation was passed to make it a lending agency to rural electric cooperatives which constructed power lines. Rural farm services in a sense combined those supplied to industry and urban homes decades earlier, extending active hours and reducing labor. Like previous technological changes in farming, it increased productivity and fueled the population shift from rural to urban life.

Following World War II new electrical services emerged, many of which like radar and computers had their roots in wartime research. Semiconductors have led in turn to telecommunications, aerospace, and computer services which define our modern age, from VCRs and CDs to materials science and high temperature plasma technology. Just as electrification spurred a society based on mass production, so these technologies are producing one based on information and customized production.

Although it is commonplace to assume that the pace of change has increased, this depends not just on technological change but the inertia of our technical infrastructure. The penetration in approximately a decade of personal computers into offices and homes is not so different from the time it took to bring public lighting or wire the majority of urban homes, and the current sense of instant change related to the Internet is not so different from that produced by the telephone or radio.

This historical review reinforces the point that the value of electricity is based on the services that it provides, and that these services have evolved into more and more valuable forms. Customers base their willingness to pay (or their demand curve) on the quality of the services they receive and the availability and quality of competing sources of these services. Following W.W.II, most new kinds of electrical services can only be provided by electricity, so the customers willingness to pay will be limited by the cost of competing sources of electricity. . For large customers these include industrial self generation or cogeneration, while for small customers there have been few options.

If electricity has become more valuable, and competition is very limited for some services, why has the price of electricity increased only in the relatively recent past? The answer is that while the demand curve for electricity has moved up, the supply curve has moved down even faster so that the price has tended to drop. The regulated utilities could not extract the consumer surplus through monopoly rents, and customers were not willing to pay more necessary.

1.2 Historical Evolution of Industry Structure

The structure of the electric utility industry has naturally evolved in an interrelated way with the customers and services which it supplies. The original market for public and commercial lighting was supplied by private generators, investor owned utilities (IOUs), and municipal generators, with no particular standardization in the voltage or frequency of the equipment. The addition of traction companies that also supplied customers with electricity added another layer of complexity to the mix of early generators.

AC generation replaced DC generation in the 1890s due to two main advantages. The AC induction motor had significant advantages over the DC motor, but the main advantage was in the ability to use transformers to increase transmission voltages and reduce transmission losses over long distances. This increased the advantages of larger utilities who could reap the benefits of a customer base with diverse loads and a flatter daily load curve, and the economies of scale which could be achieved with larger generators. This drive for larger, interconnected utilities also led to standardization of voltage, frequency and equipment.

As utilities became larger, private commercial generation became less attractive and these customers shifted to other suppliers, but private industrial generation (self generation or cogeneration) remained strong. Increasing economies of scale led to arguments against the inefficiency of redundant, parallel distribution networks and to the concept of natural monopoly, but this did not solve the question of whether it should be a private or public monopoly. Voter distrust of large industries (like Standard

Oil) fueled the impetus for municipal utilities, but investor owned utilities countered with arguments based on municipal corruption (which was rife), better private efficiency, and the fear of socialism. In 1905 the National Civic Federation created the Commission on Public Ownership which met from 1905 to 1907 and produced a report that recommended that private monopolistic utilities should be regulated by state agencies. The Federation was privately funded, and General Electric and several of the largest utilities were represented on the Commission. The recommendation meant that control of local IOUs would be removed from local elections to state regulators who could be more easily lobbied, and municipal representatives would face utility experts in a less friendly and familiar setting. The National Electric Light Association (an industry group) and individual utilities lobbied for this recommendation, and by 1921 all states but Rhode Island had adopted the current state regulatory structure.

While municipal utilities did not disappear, the private investor owned utilities became dominant. The share of industrial cogeneration shrank until 1929, when private utilities produced 75% of all power. With the start of the Depression however, industrial cogeneration experienced a resurgence which did not end until the end of the Depression and the start of W.W.II.

Even during the Depression electric utilities continued to grow, engendering public suspicion of price gouging. This public distrust was not allayed by the complex financial structure of utility ownership. Holding companies controlled many subsidiary utilities through highly leveraged ownership of voting (v. non-voting) common stocks. In 1932, the eight largest holding companies owned 73% of all IOUs. The holding company controlled by Samuel Insull (once Thomas Edison's private secretary) controlled assets of at least half a billion dollars in 1930 with a total investment of only $27 million. This situation led to the Public Utility Holding Companies Act (PUHCA) of 1935, which disbanded holding companies which controlled non-contiguous service areas and which could not demonstrate their usefulness[48] .

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[48] Hyman, Leonard S., *America's Electric Utilities: Past, Present and Future*, 5th Edition, p. 111, Public Utilities Reports, Inc., Arlington VA, 1994.

The Depression and this atmosphere of distrust led to two other developments. The first was a resurgence of municipal utilities, which outnumbered IOUs but still controlled a smaller fraction of the total market. The second development was the entrance of the federal government into the generation and wholesale distribution of power. In addition to the Rural Electrification Act (described above), Roosevelt's administration created the Tennessee Valley Authority (TVA) and the Bonneville Power Authority (BPA) to develop hydropower resources on the Tennessee and Columbia rivers. These agencies (and the single Boulder dam) were intended to combine hydropower and economic development, and to serve as a yardstick for the fairness of performance by the IOUs. During W.W.II, the TVA expanded from hydropower to thermal generation in order to power the gaseous enrichment of uranium at Oak Ridge for the Manhattan project. Following W.W.II, the electric utility sector entered a period from 1945 to 1965 which has been termed the golden age or the good old days. Utility demand grew steadily and economies of scale drove the price of electricity down in both absolute and relative terms. Generation by industrial producers dropped to almost zero, and municipal utilities became largely distributors of power purchased wholesale from IOUs.

It is obvious from this brief review of history that competition is nothing new to the utility sector. The point is however that since the institution of state regulation (from approximately 1920 on) and the decline of independent and municipal generation were several generations ago, the industry has lost any direct personal or corporate memory of competition and has accepted as gospel the regulatory compact based upon an assumed service monopoly.

The golden years of the electric utility industry came to a close in 1965, the year that the November blackout left 30 million people in darkness in interconnected power pools covering 80,000 square miles throughout the Northeast. A number of trends conspired to cause the industry's decline. The blackout caused a perceived need for higher reserve margins and more robust transmission systems, requiring new capital investments. The cost of these capital investments were rising for several reasons. First, utilities were shifting to more capital intensive generation, including nuclear plants.

Public opposition and safety regulations combined to delay construction and drive nuclear plant costs up. Second, environmental requirements increased plant costs and reduced efficiencies. Overall efficiencies did not increase with costs, and the trend of increasing economies of scale came to an end. In addition to capital costs, fuel costs were rising. The cost of coal rose sharply, and the cost of other fuels even more. In the face of these difficulties, electricity prices stayed flat until 1970, declining in real terms as the cost of living rose. Utility bookkeeping exaggerated utility incomes, since AFUDC was counted as income for accounting purposes even though it did not represent real cash flow.

As a result, the returns on utility stock declined and stock prices dropped precipitously. Utility stocks had a low perceived risk and competed with bonds. As bond yields rose independently, utility stock prices were driven down further until competitive yields were reached.. Utility shares dropped in price by half by 1975. Share prices were below book value, so that new shares issued to pay for new construction diluted existing shareholders' equity.

The fuel prices raised by the oil embargo of 1973-74 were passed on through fuel adjustment clauses, and electricity load growth in 1974 was negative for the first time since 1946. Expectations of resumed growth after the embargo proved optimistic, and growth remained low by historic levels causing excess capacity. Although electricity prices increased during the 1970's, utilities remained in weak financial condition. With the accident at Three Mile Island (1979), the conversion of the Zimmer nuclear plant to natural gas(1983), and the Washington Public Power Supply System bond default(1983), the industry continued to suffer through the early 1980's, and many nuclear utilities were pushed close to bankruptcy. Public Service of New Hampshire became the first IOU in over 50 years to declare bankruptcy due to cost overruns on its Seabrook nuclear unit.

Out of these troubled decades were sown the seeds of the current trends which are pressing towards deregulation and competition. As a result of the oil crisis, the Public Utilities Regulatory Policy Act (PURPA) guaranteed in 1978 that utilities would be required to purchase power from independent producers and other qualifying facilities at the avoided cost of the next utility generator otherwise required, although this was the subject of litigation until 1982 when PURPA was upheld by the US Supreme Court. This market access granted to non-utility generators was increased by the Energy Policy Act of 1992, which has led to significant market penetration by independent power producers, including industrial self generators and cogenerators, municipal waste fired generators, and private suppliers. Deregulation of the natural gas industry and increased confidence in natural gas reserves has promoted a new generation of gas fired generation based on aero-derivative turbines which have lower capital requirements and higher efficiencies than previous utility capacity. Continued low load growth rates due in part to increased emphasis on end-use efficiencies and load shifting have combined with this new non-utility generation to keep reserve margins high by historical standards. Efficiency gains still available and current load growth rates appear to make new capacity unnecessary for 5 to 10 years, increasing pressures to reduce costs by eliminating current high cost producers. FERC's 1988 approval of a utility merger required third party transmission access, and the Energy Policy Act of 1992 removed provisions of the Public Utilities Holding Company Act of 1935, guaranteeing open access for power wheeling and wholesale competition. The Energy Policy Act does not directly permit retail competition, but does allow the individual states to permit it. These reforms have both contributed to competitive pressures for further competition in the industry. Pilot programs for retail competition are in place in some states like New Hampshire, and electricity futures trading has begun in several markets, including the Chicago Board of Trade and the New York Mercantile Exchange.

Obviously the problems and resulting trends of the past 30 years have produced profound and rapid change in the once staid electric utility industry, and if anything the pace of change appears to be accelerating. New generators, excess capacity and open transmission access have produced incentives for competition. Deregulation in the truck, airline, natural gas and telecommunications industries have set the precedent in a continuing political environment that seems certain to assure that these incentives will result in dis-integration of the vertically integrated utility and open competition between generators.

1.3 Historical Evolution of Industry Planning

Given the historical evolution in the value of end-use services and industry structure, the question is how utility planning and the concept of value in planning has evolved over the same period.

From the beginnings of the industry through the end of the 'golden age' in 1965, the planning process was relatively simple. Planning consisted basically of the following four steps.

- Getting the load curve as flat as possible through the best possible blend of customers and an appropriate rate structure.
- Doing the best possible job of load forecasting either by extrapolating past total load growth, bottom up analysis, or top down econometric analysis.
- Choosing the most cost effective new generation additions (base, intermediate and peak load plants) through the correct balance of fixed capital and variable (fuel) costs, based on the expected plant capacity factor (hr./yr.).
- Designing a transmission and distribution system to handle normal loads and outage scenarios without constraining normal plant dispatch.

During the early days of the industry, the first step above was key, because by mixing customers whose loads peaked at different times generating plant could be much more efficiently utilized. However once utilities covered large service areas and everyone was already a customer it became much harder to influence the load duration curve.

As has been mentioned above, the investor owned utilities worked to become regulated monopolies. Once they had accomplished this, state regulatory laws and policies grew up that largely determined utility planning and how utilities perceived value. These regulations varied in some significant ways between states, but up until 1965 they were basically related to rate of return on the rate base and rate structures. Rate base regulation established utility revenues and rate structures established how customer prices were set. Good planning came to mean finding the best new additional generation capacity, according to the supply planning guidelines and decisions of the state regulators.

In return for being granted control of a 'natural' monopoly, the utilities entered into the regulatory compact which allowed a fixed rate of return on the rate base. Although utility accounting practices are a complex and arcane subject with limited connection to real economic or customer values, the rate base is basically composed of generation, transmission and distribution capital asset costs minus depreciation. The National Association of Regulatory Utility Commissioners tracks state regulatory policies which determine which assets are included in the rate base, how rate base assets are valued, the valuation methods and time periods used, and how depreciation, deductions, abandonment's, working capital, and construction work in progress (CWIP) are handled, as well as the accounting and auditing practices employed.

The approved rate of return on utility rate base varies nationally with most states in the range from 8% to 12% [49]. The larger the rate base the more utilities earn, and this incentive towards higher capitalization was recognized by Averch and Johnson in 1962[50]. The utility industry is naturally capital intensive, and as long as economies of scale drove utility costs per kWh down this incentive was not perceived to be much of a problem. Most states (all but 12) also allow utilities to automatically pass changes in fuel costs on to customers. These fuel adjustment clauses were adopted in the mid-1970's as a result of the oil price shock. Although fuel costs are subject to periodic review, this pass through can also be viewed as a disincentive to efficiency. Both of these (dis)incentives played a role in the industry's troubles as capital and fuel costs soared together.

The structural changes made in response to the industry's difficulties have been briefly sketched above. These trends can also be traced by the accretion of successive regulatory incentives and requirements which allowed

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[49] National Association of Regulatory Utility Commissioners, *Utility Regulatory Policy in the United States and Canada, Compilation 1993-1994*, Table 214, p. 465.
[50] Averch, Harvey and Johnson, Leland, "Behavior of the Firm under Regulatory Constraint," *American Economic Review*, Dec. 1962.

or produced the changes that occurred. These additions to planning requirements and proceedings have included the following.

- Supply side planning was supplemented by demand side management (DSM). These were then combined to form least cost utility planning (LCUP), which was then replaced by integrated resource planning (IRP). Regulations include how to deal with customer incentive programs, and how utilities may evaluate, allocate and recover costs and incentives for demand side activities. They also include required elements of IRP plans, evaluation of externalities, and public participation.

- The large size and cost overruns of nuclear units led to regulatory review of whether additions to the rate base were 'used and useful,' and whether in hindsight prudent planning was used as decisions were made to begin and continue construction.

- Low nuclear plant capacity factors led to regulatory incentives for improved performance.

- Environmental externalities were added to the 'least cost' choice of new capacity and DSM by assigning monetary costs to emissions. The choice of these externalities costs are subject to debate, and generation units chosen based on them are not dispatched according to these costs in operation.

- A significant number of states have authorized and/or required competitive bidding for the acquisition of not just new generation capacity, but of property, equipment and financial services.

- Regulations have begun to address the issues of pricing open access transmission across utility networks.

Obviously, regulated utility planning has become much more complex over the last 30 years. Requiring utilities to purchase power from qualifying facilities at avoided cost was certainly the first step in recognizing the marginal value of generation. Once it was clear that the utilities avoided cost was not necessarily the cheapest power available, the utilities turned to IPP generators and re negotiated or bought out many of their previous contracts with PURPA qualifying facilities. DSM also recognized the value of avoiding high marginal costs, but the questions of value lay more in how to really establish actual savings and allocate the costs and benefits. Neither development addressed the value of providing economic signals and incentives to retail customers through rates with hourly marginal cost (so called time of day (TOD) pricing, also now called real time pricing (RTP) or spot pricing). RTP pricing is now used in wholesale spot markets, but utilities with retail TOD rates generally only switch between on-peak and off-peak rates rather than setting hourly rates. Pumped or compressed air storage and customer load management are currently utilities' chief methods of flattening the load curve, but comprehensive wholesale and retail RTP pricing has the potential to not only shift customers' loads but send the correct signals all along the chain from generation to consumption.

Despite the regulatory complications added to utility planning, the basic emphasis has remained firmly on how to choose the best technology to add to the system. Planning has broadened to include both supply and demand technologies, and a range of potential suppliers, but the focus has remained on the technology in a stand alone fashion, without necessarily considering how the technology and system will interact.

1.4 Current Directions, Requirements, and Deficiencies in Utility Planning

At the present time, the US is poised to follow some other countries (chiefly Britain, which deregulated in 1987) into competitive utility markets. California already has already debated several schemes for competition and retreated briefly from implementation, while in Massachusetts proposals for competition have currently been submitted by four major utilities and the state Department of Energy Resources and are currently under review. As mentioned above, New Hampshire has in place a trial program for retail competition. A handful of other states are close behind in the deregulatory process (including Rhode Island and Wisconsin), and the rest of the country is watching closely.

It appears clear that the natural monopoly of transmission and distribution will be maintained, although they will be separated and separately regulated. Generation will be competitive and will have open access to transmission lines which will charge regulated wheeling fees. The least certain aspect is how best to structure purchase transactions in a way that will accomplish both economic and security dispatch functions. Spot markets already exist for wholesale short term power purchases, and municipal and industrial customers are already forming bargaining units to establish purchasing power in the new market.

The main two prospective market structures are a power pool and bilateral transactions. Under the pool structure, the power pool operates the transmission system and is the sole purchaser of electricity from generators and the sole seller of electricity to wholesale distributors. Supply and demand are equilibrated through a bidding system for energy, capacity, VARS and spinning reserve, and all generators are paid the marginal cost for these services on an hourly basis. Distributors pay the pool this same spot price, plus transmission costs, losses and overhead. This market coordinates generation planning and dispatch over the full time spectrum from long term (years) to short term (seconds). Retail customers pay the distributors based on the hourly market price averaged over time and service territory plus regulated distribution costs. England currently uses such a pool system, but it does have some inefficiencies which makes a bilateral market system appear more attractive. These include a lack of correct transmission pricing and retail pricing which lacks information based on system load and network location.

Under a system of bilateral transactions, any buyer may contract directly with any seller, and the market is the only coordinating force. Under this system, transmission and distribution prices are regulated based upon their costs, and a network coordinator must be established to maintain system synchronization and emergency control. Brokers would have free access to coordinate transactions between generators and customers, either individually or in groups. The chief questions under a bilateral system are how to implement the coordination function and price both it and power transmission and distribution correctly. The bilateral transaction system has the most flexibility in unbundling electricity services which would maximize value to both buyers and sellers, and appears likely to be the dominant choice among the US states. Norway currently uses a system in which bilateral long term transactions predominate, while maintaining a relatively small power pool for spot market transactions.

Unbundling is the separation of different types of electrical service so that they can supplied and billed individually, including energy (kWh), demand (kW), and transmission and distribution, as well as ancillary services like dispatch, frequency, reactive power, and power reserves required for reliability and power quality. In addition, buyers will be able to pay a slight premium for power with reduced emissions or price risks based on a blend of fuel types and contracts. A seller may also sell electrical service directly, by combining electricity with end-use technology (e.g. a more efficient appliance) for a single price. Unbundling these services is directly analogous to the proliferation of services under telephone deregulation, including call waiting and forwarding, but the common carrier delivery is more analogous to the gas pipeline. The electron entering the generator's end of the 'pipeline' is not the same one that exits the customer's end, but since they are interchangeable the contract preserves the benefits for both buyer and seller.

Under either form of deregulation, it appears that some fraction of current utility generation capacity will be uncompetitive. In a competitive marketplace the value of a generator will be the net present value of future revenues minus future costs, which are primarily fuel and O&M. The difference between the current depreciated value of capital cost yet to be recovered and the free market value is called the stranded cost. Stranded cost is most likely to be significant where capital costs are high (e.g. nuclear plants) or where units are so inefficient that their future revenues are small. Stranded costs are a transitional regulatory problem because utilities were granted regulatory approval for plant construction and were assured of a return on it. The problem is that forecasts of future revenues are uncertain, the total of stranded costs is very large, and customers are unwilling to pay for plants to be retired.

In addition to the problem of how stranded costs will be determined and allocated, deregulation also poses several other questions including how a competitive market can fulfill some of the social policies embedded in present rate structures, including equity between different classes of customers, and assistance or protection from disconnection for the poor.

Even if present utilities are separated into generation, transmission and distribution companies, it is unclear at the current time which entities will own or control these functions. Some current utilities may attempt to fulfill as many market niches or functions as possible, while others may choose to specialize. Rather than getting bogged down in *who* will be the generator, transmitter, distributor, broker, dispatcher or coordinator, the important thing to remember is that different sources of value are associated with different utility functions, so each market player will need to consider a different subset of the component values presented in this thesis.

This appendix has reviewed the historic context of utility values and regulation to give the context for the issues and problems related to current utility planning. In many ways the utility industry has returned to its roots, because the current situation has many similarities to the early development of power markets. Competition between utilities, utility mergers and acquisitions, the entry of independent generators, the importance of transmission in driving changes, and municipal bargaining power were all familiar in the pre-monopolistic industry. The current industry is concerned with high cost excess capacity, deregulation, dis-integration, and competition, but it will require better planning tools to achieve its real long term goals of cheap, clean and sustainable power.

Appendix 2

This appendix contains the Fortran program written to implement the storage optimization algorithm developed to shift generation by non-dispatchable technologies (wind and solar PV) from hours with low system marginal cost to hours with high system marginal cost, subject to the constraints of storage capacity and inverter generation capacity. The algorithm contained in this program is described in general terms in Chapter 4, and the flow chart for this algorithm is shown as Figure 4.8. Documentation in the program includes an outline, variable definition list, and comments throughout the code.

```
C        1         2         3         4         5         6         7
C 3456789 123456789 123456789 123456789 123456789 123456789 123456789 12
C     ==================================================================
C     | Program - NDT-STOR.FOR                                         |
C     | Purpose - To calculate generation from NonDispatchable         |
C     | Technologies (NDT's - i.e. wind & solar), distribute           |
C     | generation to peak load hours according to the the amount     |
C     | of storage capacity, adjust system load, and calculate         |
C     | statistics.                                                    |
C     | Written Sep/Oct 95 by Warren Schenler                          |
C     ==================================================================


      program NDTSTOR


C     Outline of algorithm
C     --------------------
C     Define variable names
C     Define variable types/lengths, dimension arrays
C     Initialize global variables
C     Read fixed data
C     Annual loop
C       Planning period loop
C         Read hourly data for each planning period
C         Convert resource data to generation data
C         Find highest available netload hour
C         Find lowest available netload hour
C         If storage constraints unviolated, swap energy
C         Repeat until all possible swaps complete
C         Update counters and statistics
C         Write output for planning period
C       Loop to next planning period
C       Write output for year
C     Loop to next year
C     Stop - error or out of data


C     Define Variable Names
C     ---------------------
C     paramfile   Contains NDTech & storage parameters
C     ndtrajfile  Contains NDT installation trajectory
C     genfile           Contains NDT hourly resource data
```

```
C     loadfile    Contains hourly system load data
C     netloadfile Contains load data net of generation & storage
C     statfile    Contains summary statistics

C     ndtype            Type of nondispatchable technology (WIND or PV)
C     techname    Name of nondispatchable technology (eg turbine name)
C     ndunitcap   Nondispatchable unit capacity (MW)
C     storage           Storage fraction (0 to 1) or capacity (MWh/MW)
C     storgencap  Generation capacity from storage (multiple of NDT cap)
C     pdays       Number of days in storage opt. planning period
C     firstyr           First year in planning period
C     pyears            Number of years in planning period
C     siteloss    Energy loss at site
C     spurloss    Energy loss from site to NEPOOL region
C     TDloss            Energy loss within NEPOOL region (as for regular gen.)
C     VOM         Variable operation & maintenance cost

C     capyear           Year of new capacity level
C     ndcap(yr)   Nondispatchable capacity (by year)

C     ldmon1-2    Month of year for system load
C     genmon            Month of year for NDT generation
C     ldday1-2    Day of month for system load
C     genday            Day of month for NDT generation
C     ldyr1-2           Year for system load
C     genyr       Year for NDT generation
C     ldwkday1-2  Day of week (Sun=1,Sat=7) for system load
C     genwkday    Day of week (Sun=1,Sat=7) for NDT generation
C     ldampm1-2   AM(1) or PM(2) for system load
C     genampm           AM(1) or PM(2) for NDT generation
C     hrload(i)   Hourly system load
C     hrresc(i)   Hourly resource data

C     hrgen(i)    Hourly NDT generation
C     hrstorin(i) Hourly energy into storage
C     hrstorout(i)      Hourly energy out of storage
C     hrnet(i)    Hourly net load

C     daygen            Total generation per day
C     maxdaygen   Maximum daily generation
C     storcap           Storage capacity for current year (MWh)
C     phr         Hours of planning period overlap

C     anngen            Annual generation (MWh)
C     capfac            Annual capacity factor
C     annstor           Annual storage (MWh)
C     storfrac    Annual storage fraction (storage/gen)
C     capcredit   Annual capacity credit (MW)
C     annVOM            Annual VOM total ($)


C     Define variable types/lengths, dimension arrays
C     -----------------------------------------------

      character paramfile*30,ndtrajfile*30,genfile*30,loadfile*30,
     1          netloadfile*30,statfile*30,ndtype*30,techname*30,tab*1

      real ndunitcap,storage,storgencap,siteloss,spurloss,TDloss,
```

```
     1     VOM,ndcap(30),daygen,maxdaygen
      real hrload(-25:750),hrresc(750),hrgen(-25:750),
     1     hrstorin(-25:750),hrstorout(-25:750),hrnet(-25:750),
     2     maxload1(11),maxload2(11),maxload3(11)
      real storcap,anngen,capfac,annstor,storfrac,capcredit,annVOM,
     1         gap,gaplow,gaphigh,lowld,highld,cumstor,minstor,maxstor,
     2     tempcum,aveload

      integer pdays,firstyr,pyears,capyear,genmon,genday,genyr,
     1        rank(750),yr,curgenyr,pday1,pday2,highhr,lowhr
      integer phr1,phr2,phr,pos,nhigh,nlow,hrinok(750),hroutok(750)
      integer ldmon1(-2:31),ldmon2(-2:31),ldday1(-2:31),ldday2(-2:31),
     1        ldyr1(-2:31),ldyr2(-2:31),ldwkday1(-2:31),
     2        ldwkday2(-2:31),ldampm1(-2:31),ldampm2(-2:31)


C     Initialize global variables
C     ---------------------------
      do i=1,30
         ndcap(i) = 0.
      end do


C     Read filenames and open files
C     -----------------------------

      read(*,fmt=10) len,paramfile
10    format(q,a30)
      read(*,*) storgencap
      read(*,*) storage
      paramfile = paramfile(1:len)
      do i=1,len
         if(paramfile(i:i).eq.'.') then
            pos = i-1
         end if
      end do
      if(paramfile(1:2).eq.'PV') then
         open (01,file='PV.DAT',status='old',carriagecontrol='list')
      elseif(paramfile(1:4).eq.'WIND') then
         open (01,file='WIND.DAT',status='old',carriagecontrol='list')
      else
         open (01,file=paramfile,status='old',carriagecontrol='list')
      endif
      rewind (01)
      statfile = paramfile(1:pos)//'.SUM'
      open (06,file=statfile,status='new',carriagecontrol='list')
      write(*,20) paramfile
      write(6,20) paramfile
20    format(' NDT/Storage parameter file:    ',a<len>)

      read(*,fmt=10) len,ndtrajfile
      ndtrajfile = ndtrajfile(1:len)
      open (02,file=ndtrajfile,status='old',carriagecontrol='list')
      rewind (02)
      write(*,30) ndtrajfile
      write(6,30) ndtrajfile
30    format(' NDT capacity trajectory file:  ',a<len>)
```

```
      read(*,fmt=10) len,genfile
      genfile = genfile(1:len)
      open (03,file=genfile,status='old',recl=150)
      rewind (03)
      write(*,40) genfile
      write(6,40) genfile
40    format(' NDT hourly resource file:      ',a<len>)

      read(*,fmt=10) len,loadfile
      loadfile = loadfile(1:len)
      open (04,file=loadfile,status='old',recl=80)
      rewind (04)
      write(*,50) loadfile
      write(6,50) loadfile
50    format(' Hourly system load file:       ',a<len>)

      netloadfile = paramfile(1:pos)//'.NET'
      open (05,file=netloadfile,status='new',carriagecontrol='list')
      write(*,60) netloadfile
      write(6,60) netloadfile
60    format(' Net hourly system load file:   ',a<len>)

      write(*,70) statfile
      write(6,70) statfile
70    format(' Summary statistics file:       ',a<pos+4>)


C     Read fixed parameter data
C     -------------------------

      read(01,fmt=10) len1,ndtype
      read(01,fmt=10) len2,techname
      read(01,*) ndunitcap
      read(01,*) !storage       Presently get these two data by
      read(01,*) !storgencap    reading com file
      read(01,*) pdays
      read(01,*) firstyr
      read(01,*) pyears
      read(01,*) siteloss
      read(01,*) spurloss
      read(01,*) TDloss
      read(01,*) vom

      close(01)

      write(*,*) 'Type of NDT:        ',ndtype
      write(*,*) 'Technology name:    ',techname
      write(*,*) 'NDT Unit capacity:  ',ndunitcap
      write(*,*) 'Storage:            ',storage
      write(*,*) 'Storage gen cap:    ',storgencap
      write(*,*) 'Storage opt days:   ',pdays
      write(*,*) 'First year:         ',firstyr
      write(*,*) 'Planning period:    ',pyears
      write(*,*) 'Site loss:          ',siteloss
      write(*,*) 'Spur line loss:     ',spurloss
      write(*,*) 'T & D loss:         ',TDloss
      write(*,*) 'Variable O&M:       ',vom
```

```
      tloss = (1+spurloss)*(1+TDloss)

C     Read annual capacities, fill in trajectory, round up
C     to integer multiple of unit capacity, and test write.
C     -----------------------------------------------------

      read(02,*)
      do i=1,pyears
         read(02,*,end=80) capyear,ndcap(capyear-firstyr+1)
      end do
80    do i=2,pyears
         if(ndcap(i).eq.0.) then
            ndcap(i) = ndcap(i-1)
         end if
      end do
      do i=1,pyears
         ndcap(i) = ndunitcap*real(nint(ndcap(i)/ndunitcap))
      end do
      write(*,*)
      write(*,*)'Year   NDT Cap'
      do i=1,pyears
         write(*,90) firstyr+i-1, ndcap(i)
      end do
90    format(i5,f10.0)
      close(02)


C     Annual loop. Initialize annual variables.
C     -----------------------------------------

100   do 400 yr = 1,pyears

      anngen    = 0.
      capfac    = 0.
      annstor   = 0.
      storfrac  = 0.
      capcredit = 0.
      annVOM    = 0.
      do i = 1,11
         maxload1(i) = 0.
         maxload2(i) = 0.
         maxload3(i) = 0.
      end do

C     Find storage capacity for year if NDT capacity has changed.
C     First check NDT type, then read data. NDT resource data may have
C     more than 1 year, so if year changes reset current year and rezero
C     counter. If year read is beyond current year in annual loop, stop
C     and find size of storage.  Note that storagen generation capacity
C     grows with NDT capacity, and that the maximum day's generation is
C     assumed to constant from year to year.
C     --------------------------------------

      if(yr.gt.1)then
         if(ndcap(yr).eq.ndcap(yr-1)) then
            go to 200              ! Storage capacity remains constant.
         end if                    ! Go to planning period loop.
```

```
      end if

      curgenyr = 0
      if((ndtype(1:len1) .eq. 'WIND') .or.
     1    (ndtype(1:len1) .eq. 'Wind') .or.
     2    (ndtype(1:len1) .eq. 'wind')) then
         if(techname(1:len2).ne.'AOC33350') then
            write(*,*) 'Wind turbine type not recognized'
         endif

110      read(03,120,err=150,end=160) genmon,genday,genyr,
     1                                (tab,hrresc(i),i=1,24)
120      format (3I2,24(A1,F4.1))

         if(genyr.ne.curgenyr) then
            curgenyr = genyr
            maxdaygen  = 0.
         elseif((1900+genyr).gt.(firstyr+yr-1)) then
            go to 160
         endif

         daygen = 0.
         do i=1,24
            if((hrresc(i).lt.4.0) .OR. (hrresc(i).gt.25.0)) then
               hrgen(i) = 0.
            else
               hrgen(i) = -34.253 - 7.6058*hrresc(i) +
     1                    4.7113*(hrresc(i)**2) -
     2                    0.16918*(hrresc(i)**3)
            endif
            hrgen(i) = hrgen(i)/(1+siteloss)
            daygen = daygen + hrgen(i)
         end do
         maxdaygen = max(daygen,maxdaygen)
         go to 110                          ! Read next day


      elseif((ndtype(1:len1) .eq. 'PV') .or.
     1        (ndtype(1:len1) .eq. 'pv')) then
130      read(03,140,err=150,end=160) genmon,genday,genyr,
     1                                (tab,hrresc(i),i=1,24)
140      format (3I2,24(A1,F5.3))
         if(genyr.ne.curgenyr) then
            curgenyr  = genyr
            maxdaygen = 0.
         elseif((1900+genyr).gt.(firstyr+yr-1)) then
            go to 160
         endif

         daygen = 0.
         do i=1,24
            hrgen(i) = ndcap(yr)*hrresc(i)
            hrgen(i) = hrgen(i)/(1+siteloss)
            daygen = daygen + hrgen(i)
         end do
         maxdaygen = max(daygen,maxdaygen)
         go to 130   ! Read next day
```

```
      else
         write(*,*) 'NDT type not recognized'
      endif

150   write(*,*) 'Error reading generation resource file'
160   rewind (03)


C     If storage variable read is 0->1, then capacity is this fraction
C     of the maximum daily generation.  If >1, then storage equals
C     this number of hours at peak capacity.  Generation capacity from
C     storage is given as a fraction (0-1) of raw NDT generation
C     capacity, so redefine and reduce by site losses to give equivalent
C     net capacity.
C     -------------

      if(storage.lt.0.) then
         write(*,*) 'Negative storage capacity not allowed'
      elseif(storage.le.1.) then
         storcap = storage*maxdaygen
      else
         storcap = storage*ndcap(yr)
      endif
      storgencap = storgencap*ndcap(yr)/(1+siteloss)

      write(*,*)
      write(*,*) 'MaxDayGen   Storage   StorCap   NdtCap   InvCap'
      write(*,170) maxdaygen,storage,storcap,ndcap(yr),storgencap
      write(*,*)
170   format(5F10.1)


C     Initialize data before planning period loop.
C     ---------------------------------------------

      do i=1,750
         hrstorin(i)  = 0.
         hrstorout(i) = 0.
      end do
      do i=-25,750
         hrgen(i)  = 0.
         hrload(i) = 0.
         hrnet(i)  = 0.
      end do


C     Planning period loop.  Initalize data for period.
C     -------------------------------------------------

200   continue

      do i=1,750
         hrresc(i) = 0.
         rank(i)   = i
      end do
      pday1 = 0
      pday2 = pdays
      phr   = 0
```

```
      ihr1  = 0
      iday1 = 0

      if((pdays.le.0) .or.(pdays.gt.31)) then
         write(*,*) 'Planning period must be 1->31 days'
      endif


C     If planning period is an even number of weeks, read first line for
C     day of week and adjust first planning period to end on Saturday.
C     Note: Mo=1,Tu=2,We=3,Th=4,Fr=5,Sa=6,Su=7.
C     -----------------------------------------

      if(mod(pdays,7).eq.0) then
         read(04,220,err=600,end=600) ldmon1(1),ldday1(1),ldyr1(1),
     1        ldampm1(1),ldwkday1(1),(hrload(i),i=1,12)
220      format(T1,I2,T3,I2,T5,I2,T7,I1,T16,I1,T21,12F5.0)
         rewind(04)

         if(ldwkday1(1).le.3) then
            pday1 = pdays-ldwkday1(1)
         else
            pday1 = pdays-ldwkday1(1)+7
         endif
         pdays = pday1
      end if


C     Check NDT type to choose generation function (hrgen = f(hrresc)).
C     Read data for planning period.  As generation is calculated, keep
C     track of annual generation and 10 highest hourly system loads,
C     before and after NDT generation.  If data ends before end of year,
C     write error message and exit.  At year end, abbreviate current
C     planning period if needed.
C     --------------------------

240   if((ndtype(1:len1) .eq. 'WIND') .or.
     1      (ndtype(1:len1) .eq. 'Wind') .or.
     2      (ndtype(1:len1) .eq. 'wind')) then

      do k=1,pdays
         j = 24*(k-1)
         read(03,120,err=600,end=600) genmon,genday,genyr,
     1                                 (tab,hrresc(i),i=j+1+phr,j+24+phr)
         read(04,220,err=600,end=600) ldmon1(k),ldday1(k),ldyr1(k),
     1        ldampm1(k),ldwkday1(k),(hrload(i),i=j+1+phr,j+12+phr)
         read(04,220,err=600,end=600) ldmon2(k),ldday2(k),ldyr2(k),
     1        ldampm2(k),ldwkday2(k),(hrload(i),i=j+13+phr,j+24+phr)
         if((ldmon1(k).eq.12).and.(ldday1(k).eq.31)) go to 241
      end do
      go to 242
241   pdays = k
242   continue

C     In this case input files have been well examined, but for more
C     general applications, this section should check for the same
C     dates in resource v. load data, leapyears, missing or out of
C     sequence data. etc.  Resource data may need to rewind if fewer
```

```
C     years are available than needed to match forecast load data.

      do i = 1+phr,24*pdays+phr
         if((hrresc(i).lt.4.0).or.(hrresc(i).gt.25.0)) then
            hrgen(i) = 0.
         else
            hrgen(i) = -34.253 - 7.6058*hrresc(i) +
     1                    4.7113*(hrresc(i)**2) -
     2                    0.16918*(hrresc(i)**3)
            hrgen(i) = hrgen(i)/(1+siteloss)
         end if
         anngen = anngen + hrgen(i)
         maxload1(11) = hrload(i)
         j = 10
         do while((maxload1(j+1).gt.maxload1(j)).and.(j.ge.1))
            swaptemp = maxload1(j+1)
            maxload1(j+1) = maxload1(j)
            maxload1(j) = swaptemp
            j = j - 1
         end do
         hrstorout(i) = min(hrgen(i),storgencap)
         hrstorin(i) = hrstorout(i)
         hrnet(i) = hrload(i) - hrstorout(i)/tloss
         maxload2(11) = hrnet(i)
         j = 10
         do while((maxload2(j+1).gt.maxload2(j)).and.(j.ge.1))
            swaptemp = maxload2(j+1)
            maxload2(j+1) = maxload2(j)
            maxload2(j) = swaptemp
            j = j - 1
         end do
      end do


      elseif((ndtype(1:len1) .eq. 'PV') .or.
     1       (ndtype(1:len1) .eq. 'pv')) then

      do k=1,pdays
         j = 24*(k-1)
         read(03,140,err=600,end=600) genmon,genday,genyr,
     1                               (tab,hrresc(i),i=j+1+phr,j+24+phr)
         read(04,220,err=600,end=600) ldmon1(k),ldday1(k),ldyr1(k),
     1        ldampm1(k),ldwkday1(k),(hrload(i),i=j+1+phr,j+12+phr)
         read(04,220,err=600,end=600) ldmon2(k),ldday2(k),ldyr2(k),
     1        ldampm2(k),ldwkday2(k),(hrload(i),i=j+13+phr,j+24+phr)
         if((ldmon1(k).eq.12).and.(ldday1(k).eq.31)) go to 243
      end do
      go to 244
243   pdays = k
244   continue

      do i = 1+phr,24*pdays+phr
         hrgen(i) = ndcap(yr)*hrresc(i)
         hrgen(i) = hrgen(i)/(1+siteloss)
         anngen = anngen + hrgen(i)
         maxload1(11) = hrload(i)
         j = 10
         do while((maxload1(j+1).gt.maxload1(j)).and.(j.ge.1))
```

```
            swaptemp = maxload1(j+1)
            maxload1(j+1) = maxload1(j)
            maxload1(j) = swaptemp
            j = j - 1
         end do
         hrstorout(i) = min(hrgen(i),storgencap)
         hrstorin(i) = hrstorout(i)
         hrnet(i) = hrload(i) - hrstorout(i)/tloss
         maxload2(11) = hrnet(i)
         j = 10
         do while((maxload2(j+1).gt.maxload2(j)).and.(j.ge.1))
            swaptemp = maxload2(j+1)
            maxload2(j+1) = maxload2(j)
            maxload2(j) = swaptemp
            j = j - 1
         end do
      end do

      end if


C     The basic optimization algorithm used is to store energy in
C     cheap hours (low system load) and to generate in expensive hours.
C     The steps are as follows.  First, find the highest available
C     hour(s) and the energy gap to the next lowest hour or available
C     generation capacity.  Second, find the lowest available hour(s)
C     and the energy gap to the next highest hour or available NDT
C     generation.  Hours are marked 0 = unavailable, 1 = available,
C     2 = highest/lowest, and 3 = excess(free) generation above inverter
C     capacity.  If storage constraints (0<=cumstor<=storcap) are not
C     violated, a swap is made.  If can't swap, mark low hour as
C     unavailable and find next highest hour.  If no available low hours,
C     mark high hour as unavailable and go to next lowest hour.  If a
C     swap is made, all hours are remarked available.  If no swap is
C     possible, exit to next section.  An epsilon of 0.5 is used to
C     allow for roundoff error and speed of computation, since all output
C     is rounded to whole integers.
C     -----------------------------


260   continue

C     Diagnostic write for each energy swap
C     cumstor = 0.
C     do i = 1,24*pdays+phr
C        cumstor = cumstor + hrstorin(i) - hrstorout(i)
C        temp1 = (hrstorin(i)-min(hrgen(i),storgencap))/tloss
C        temp2 = (hrstorin(i)-hrstorout(i))/tloss-temp1
C        write(*,262) i,hrload(i),hrgen(i)/tloss,temp1,temp2,
C     1                 hrnet(i),cumstor,hrinok(i),hroutok(i)
C     end do
C     write(*,*)
C262  format(i4,f9.1,3f7.1,2f9.1,2i3)


C     Start search for new high hour by reinitializing markers
C     for all hours.
C     --------------
```

```
      do i = 1,24*pdays+phr
         hroutok(i) = 1
      end do


265   continue

C     Sweep through hourly net loads to find the highest hour
C     marked available and with unused generation capacity.
C     Track the high net load, the first hour with this load,
C     and number of hours with this load.  Find the minimum
C     energy gap to available capacity in peak hours and the
C     next highest net load.
C     ----------------------

      highld = 0.
      highhr = 0
      nhigh  = 0
      do i = 1,24*pdays+phr
         if(hroutok(i).eq.2) hroutok(i) = 1
         if((storgencap-hrstorout(i).gt.0.5).and.
     1        (hroutok(i).eq.1)) then
            if(hrnet(i).gt.highld+0.5) then
               gaphigh = min((hrnet(i)-highld)*tloss,
     1                       storgencap-hrstorout(i))
               highld = hrnet(i)
               highhr = i
               nhigh  = 1
            elseif((hrnet(i).ge.highld-0.5).and.
     1                 (hrnet(i).le.highld+0.5)) then
               gaphigh = min(gaphigh,storgencap-hrstorout(i))
               nhigh = nhigh + 1
            elseif((hrnet(i).lt.highld-0.5).and.
     1             (hrnet(i).gt.highld-gaphigh/tloss)) then
               gaphigh = min(gaphigh,(highld-hrnet(i))*tloss)
            end if
         end if

C        Diagnostic write for high hour data sweep
C        write(*,268) i,hrnet(i),(storgencap-hrstorout(i))/tloss,
C    1                 nhigh,highhr,highld,gaphigh/tloss
C268     format(i3,f8.0,f6.1,i4,i3,f8.0,f6.1)

      end do

      do i = 1,24*pdays+phr
         if((hroutok(i).eq.1).and.
     1        (storgencap-hrstorout(i).gt.0.5).and.
     2        (hrnet(i).le.highld+0.5).and.
     3        (hrnet(i).ge.highld-0.5)) then
            hroutok(i) = 2
         end if
      end do

      if(nhigh.eq.0) go to 280   ! EXIT OPTIMIZATION FOR THIS PERIOD
```

```
C     Reinitialize all low hour availability markers.
C     -----------------------------------------------

      do i = 1,24*pdays+phr
         hrinok(i) = 1
      end do

C     Sweep through planning period to find hour with the lowest net
C     load that is marked available and has energy available for
C     storage.  Exactly analogous to high hour search, EXCEPT search
C     first for hours where hourly generation exceeds inverter capacity.
C     If not stored this energy is wasted, so it is essentially free.
C     If no low hour is available, loop above to 265 to find next
C     lower high hour.
C     ---------------

270   continue
      lowld  = 100000.
      lowhr  = 0
      nlow   = 0
      capgap = 100000.
      do i = 1,24*pdays+phr
         if(hrinok(i).ge.2) hrinok(i) = 1
         if(((hrgen(i)-hrstorin(i)).gt.0.5).and.(hrinok(i).eq.1)) then
            if(capgap.eq.100000) then
               lowld = 0.
               gaplow = 0.
               nlow = 0
            end if
            if(hrgen(i)-hrstorin(i).lt.capgap) then
               capgap = hrgen(i)-hrstorin(i)
               lowhr = i
            end if
            nlow = nlow + 1
         elseif((hrstorout(i).gt.0.5).and.(hrinok(i).eq.1)) then
            if(hrnet(i).lt.lowld-0.5) then
               gaplow = min((lowld-hrnet(i))*tloss,hrstorout(i))
               lowld = hrnet(i)
               lowhr = i
               nlow  = 1
            elseif((hrnet(i).ge.lowld-0.5).and.
     1                 (hrnet(i).le.lowld+0.5)) then
               gaplow = min(gaplow,hrstorout(i))
               nlow = nlow + 1
            elseif((hrnet(i).gt.lowld+0.5).and.
     1             (hrnet(i).lt.lowld+gaplow/tloss)) then
               gaplow = min(gaplow,(hrnet(i)-lowld)*tloss)
            endif
         end if

C        Diagnostic write for low hour data sweep
C        write(*,272) i,hrnet(i),hrstorout(i)/tloss,
C     1                  (hrgen(i)-hrstorin(i))/tloss,nlow,lowhr,
C     2                  lowld,gaplow/tloss,capgap/tloss
C272     format(i3,f8.0,2f6.1,i4,i3,f8.0,f6.1,f9.1)

      end do
```

```
      if(lowld.eq.0.) then
         do i = 1,24*pdays+phr
            if((hrinok(i).eq.1).and.
     1              (hrgen(i)-hrstorin(i)).gt.0.5) then
               hrinok(i) = 3
            end if
         end do
      else
         do i = 1,24*pdays+phr
            if((hrinok(i).eq.1).and.
     1              (hrstorout(i).gt.0.5).and.
     2              (hrnet(i).le.lowld+0.5).and.
     3              (hrnet(i).ge.lowld-0.5)) then
               hrinok(i) = 2
            end if
         end do
      end if


      if(lowld.eq.0.) gaplow = capgap


C     If no low netload hours are available or if the low hour
C     is above the high hour, then mark the high hour as
C     unavailable and loop to find the next lower high hour.
C     ------------------------------------------------------

      if((highld-lowld.lt.0.5).or.(nlow.eq.0)) then
         hroutok(highhr) = 0
         go to 265
      end if


C     One goal is to swap as much energy as possible without repeating
C     the previous high/low search.  To swap energy for all the high/low
C     hours identified, the hourly gap is converted to a total energy gap.
C     A weighted energy average is found, and if the proposed swap
C     raises/lowers the low/high hour above/below the average, then the
C     gap is reduced so high/low hours meet at the average.  If a sweep
C     through the planning period shows that the storage constraints are
C     unviolated, then the energy exchange is made.  Note that when there
C     is excess generation (hrinok=3) hrstorin is increased, but when
C     'non-excess' energy is stored, hrstorout is decreased.
C     ------------------------------------------------------

      gaplow = gaplow*nlow
      gaphigh = gaphigh*nhigh
      gap = min(gaplow,gaphigh)
      aveload = lowld + (highld-lowld)*real(nhigh)/real(nlow+nhigh)
      if(((lowld+gaplow/real(nlow)).ge.aveload).and.
     1    ((highld-gaphigh/real(nhigh)).le.aveload))then
         gap = (real(nlow)*(aveload-lowld)+
     1           real(nhigh)*(highld-aveload))*tloss/2
      end if

      cumstor = 0.
      minstor = 100000.
      maxstor = 0.
```

```
      do i = 1,24*pdays+phr
         cumstor = cumstor + hrstorin(i) - hrstorout(i)
         if(hrinok(i).ge.2) then
            cumstor = cumstor + gap/nlow
         elseif(hroutok(i).eq.2) then
            cumstor = cumstor - gap/nhigh
         endif
         minstor = min(minstor,cumstor)
         maxstor = max(maxstor,cumstor)
      end do

      if((minstor.ge.-0.5).and.(maxstor.le.storcap+0.5)) then
         do i = 1,24*pdays+phr
            if(hrinok(i).eq.3) then
               hrstorin(i)  = hrstorin(i) + gap/nlow
            elseif(hrinok(i).eq.2) then
               hrstorout(i) = hrstorout(i) - gap/nlow
               hrnet(i) = hrload(i) - hrstorout(i)/tloss
            elseif(hroutok(i).eq.2) then
               hrstorout(i) = hrstorout(i) + gap/nhigh
               hrnet(i) = hrload(i) - hrstorout(i)/tloss
            end if
         end do

C        Diagnostic write for high/low hours and energy gaps
C        write(*,274) nlow,lowhr,lowld,gaplow/nlow/tloss,nhigh,highhr,
C     1                highld,gaphigh/nhigh/tloss,aveload,gap/tloss,
C     2                minstor,maxstor
C274     format(2(i4,i3,f8.0,f6.1),f8.0,2f6.1,f8.1)

      go to 260            ! Start over looking for lowhr/highhr
      end if


C     If the energy swap above violated storage constraints, attempt
C     to swap energy between a single pair of hours.  The energy gap is
C     reconverted to a single hour basis.  If the swap causes the
C     high/low hours to reverse, the gap is again reduced to meet in the
C     middle.  The hourly storage sweep is repeated, and if OK a swap
C     is made.  If storage constraints (low,high or both) are less than
C     the gap size, the gap is reduced and the swap is made.  If no
C     swap is possible, the low hour is marked as unavailable.  Loop
C     to 270 to find next higher low hour.
C     ------------------------------------

      gaplow = gaplow/nlow
      gaphigh = gaphigh/nhigh
      gap = min(gaplow,gaphigh)
      aveload = (lowld+highld)/2
      if(((lowld+gaplow).ge.aveload).and.
     1    ((highld-gaphigh).le.aveload))then
         gap = (highld-lowld)/2
      end if

      cumstor = 0.
      minstor = 100000.
      maxstor = 0.
      do i = 1,24*pdays+phr
```

```
         cumstor = cumstor + hrstorin(i) - hrstorout(i)
         if(i.eq.lowhr) then
            cumstor = cumstor + gap
         elseif(i.eq.highhr) then
            cumstor = cumstor - gap
         endif
         minstor = min(minstor,cumstor)
         maxstor = max(maxstor,cumstor)
      end do

C     Diagnostic write for high/low hours and energy gaps
C     write(*,276) nlow,lowhr,lowld,gaplow/nlow/tloss,nhigh,
C     1             highhr,highld,gaphigh/nhigh/tloss,aveload,
C     2             gap/tloss,minstor,maxstor
C276  format(2(i4,i3,f8.0,f6.1),f8.0,2f6.1,f8.1)

      if((minstor.ge.-0.5).and.(maxstor.le.storcap+0.5)) then
         if(hrinok(lowhr).eq.3) then
            hrstorin(lowhr) = hrstorin(lowhr) + gap
         elseif(hrinok(lowhr).eq.2) then
            hrstorout(lowhr) = hrstorout(lowhr) - gap
            hrnet(lowhr) = hrload(lowhr) - hrstorout(lowhr)/tloss
         end if
         hrstorout(highhr) = hrstorout(highhr) + gap
         hrnet(highhr) = hrload(highhr) - hrstorout(highhr)/tloss
         go to 260
      elseif(((minstor.lt.-0.5).and.(minstor.gt.-gap+0.5)).and.
     1        (maxstor.le.storcap+0.5)) then
         gap = gap+minstor
         if(hrinok(lowhr).eq.3) then
            hrstorin(lowhr) = hrstorin(lowhr) + gap
         elseif(hrinok(lowhr).eq.2) then
            hrstorout(lowhr) = hrstorout(lowhr) - gap
            hrnet(lowhr) = hrload(lowhr) - hrstorout(lowhr)/tloss
         end if
         hrstorout(highhr) = hrstorout(highhr) + gap
         hrnet(highhr) = hrload(highhr) - hrstorout(highhr)/tloss
         go to 260
      elseif((minstor.ge.-0.5).and.
     1        ((maxstor.gt.storcap+0.5).and.
     2        (maxstor.lt.storcap+gap-0.5))) then
         gap = gap-(maxstor-storcap)
         if(hrinok(lowhr).eq.3) then
            hrstorin(lowhr) = hrstorin(lowhr) + gap
         elseif(hrinok(lowhr).eq.2) then
            hrstorout(lowhr) = hrstorout(lowhr) - gap
            hrnet(lowhr) = hrload(lowhr) - hrstorout(lowhr)/tloss
         end if
         hrstorout(highhr) = hrstorout(highhr) + gap
         hrnet(highhr) = hrload(highhr) - hrstorout(highhr)/tloss
         go to 260
      elseif(((minstor.lt.-0.5).and.(minstor.gt.-gap+0.5)).and.
     1        ((maxstor.gt.storcap+0.5).and.
     2        (maxstor.lt.storcap+gap-0.5))) then
         gap = min(gap+minstor,gap-(maxstor-storcap))
         if(hrinok(lowhr).eq.3) then
            hrstorin(lowhr) = hrstorin(lowhr) + gap
         elseif(hrinok(lowhr).eq.2) then
```

```
            hrstorout(lowhr) = hrstorout(lowhr) - gap
            hrnet(lowhr) = hrload(lowhr) - hrstorout(lowhr)/tloss
         end if
         hrstorout(highhr) = hrstorout(highhr) + gap
         hrnet(highhr) = hrload(highhr) - hrstorout(highhr)/tloss
         go to 260
      end if

      hrinok(lowhr) = 0
      go to 270               ! Look for next higher low hour.


C     Update statistics for planning period.  Find next to last hour in
C     period when stored energy is zero.  Then increase this period up
C     to an integral number of days.  Print net hourly loads for
C     planning period, then take the trailing period and tack it in
C     front of the next planning period, to reduce planning distortion,
C     due to end of period effects.
C     -----------------------------

280   continue
      do i = 1,24*pdays+phr
         maxload3(11) = hrnet(i)
         j = 10
         do while((maxload3(j+1).gt.maxload3(j)).and.(j.ge.1))
            swaptemp = maxload3(j+1)
            maxload3(j+1) = maxload3(j)
            maxload3(j) = swaptemp
            j = j - 1
         end do
      end do

      do i = phr+1,24*pdays+phr
         annstor = annstor + hrstorin(i)
      end do

      phr1 = phr
      cumstor = 0.
      i = 24*pdays+phr
      do while ((cumstor.ge.0.).and.(cumstor.lt.0.5).and.
     1            (i.ge.24*pdays+phr-24))
         cumstor = cumstor - hrstorin(i) + hrstorout(i)
         i = i - 1
      end do
      phr2 = 24*pdays+phr - i - 1
      if(phr2.eq.24) phr2 = 0

      do while ((cumstor.gt.0.5).and.(i.ge.24*pdays+phr-24))
         cumstor = cumstor - hrstorin(i) + hrstorout(i)
         i = i - 1
      end do
      if(i.gt.24*pdays+phr-24) phr2 = 24*pdays+phr - i

      ihr2 = 24 - mod(phr2,24)        ! # hrs to complete full day(s)
      if(ihr2.eq.24) ihr2 = 0
      if((ldmon1(pdays).eq.12).and.(ldday1(pdays).eq.31)) ihr2 = 0
      iday2 = (phr2+ihr2)/24          ! Integer # of days to move
```

```
C     Adjust planning (pdays) period by leading and trailing intervals,
C     Copy trailing day data to leading days below as well.
C     -----------------------------------------------------

C     Summary diagnostic write for each planning period
C     cumstor = 0.
C     do i = 1,24*pdays+phr
C        cumstor = cumstor + hrstorin(i) - hrstorout(i)
C        temp1 = (hrstorin(i)-min(hrgen(i),storgencap))/tloss
C        temp2 = (hrstorin(i)-hrstorout(i))/tloss-temp1
C        write(*,310) i,hrload(i),hrgen(i)/tloss,temp1,temp2,
C     1                  hrnet(i),cumstor,hrinok(i),hroutok(i)
C     end do
C310  format(i4,f9.1,3f7.1,2f9.1,2i3)
C     write(*,*) phr2,ihr2,pday2,iday2
C     write(*,*)


      do k = -iday1+1,pdays-iday2
         j = 24*(k+iday1-1) - ihr1
         write(05,320) ldmon1(k),ldday1(k),ldyr1(k),ldampm1(k),
     1                 ldwkday1(k),(int(hrnet(i)),i=j+1,j+12)
         write(05,320) ldmon2(k),ldday2(k),ldyr2(k),ldampm2(k),
     1                 ldwkday2(k),(int(hrnet(i)),i=j+13,j+24)
      end do
320      format(T1,I2,T3,I2,T5,I2,T7,I1,T16,I1,T21,12I5)

      do i = -ihr2+1,phr2
         hrload(i)    = hrload   (24*pdays+phr1-phr2+i)
         hrgen(i)     = hrgen    (24*pdays+phr1-phr2+i)
         hrstorin(i)  = hrstorin (24*pdays+phr1-phr2+i)
         hrstorout(i) = hrstorout(24*pdays+phr1-phr2+i)
         hrnet(i)     = hrnet    (24*pdays+phr1-phr2+i)
      end do

      do i = phr2+1,24*pdays+phr1
         hrload(i)    = 0.
         hrgen(i)     = 0.
         hrstorin(i)  = 0.
         hrstorout(i) = 0.
         hrnet(i)     = 0.
      end do

      do i = -iday2,0,1
         ldmon1(i)   = ldmon1(pdays+i)
         ldmon2(i)   = ldmon2(pdays+i)
         ldday1(i)   = ldday1(pdays+i)
         ldday2(i)   = ldday2(pdays+i)
         ldyr1(i)    = ldyr1(pdays+i)
         ldyr2(i)    = ldyr2(pdays+i)
         ldampm1(i)  = ldampm1(pdays+i)
         ldampm2(i)  = ldampm2(pdays+i)
         ldwkday1(i) = ldwkday1(pdays+i)
         ldwkday2(i) = ldwkday2(pdays+i)
      end do

      do i = 1,pdays
```

```
            ldmon1(i)    = 0
            ldmon2(i)    = 0
            ldday1(i)    = 0
            ldday2(i)    = 0
            ldyr1(i)     = 0
            ldyr2(i)     = 0
            ldampm1(i)   = 0
            ldampm2(i)   = 0
            ldwkday1(i) = 0
            ldwkday2(i) = 0
         end do

C        write(*,*) ldmon1(0),ldday1(0),ldyr1(0),pdays

         phr    = phr2
         ihr1   = ihr2
         pdays = pday2       ! Reset planning period days after first period.
         iday1 = iday2


C        If end of year continue, otherwise loop to next planning period.
C        ----------------------------------------------------------------

         if((ldmon1(0).ne.12).or.(ldday1(0).ne.31)) then
            go to 240
         end if


C        Write summary statistics for year and loop to next year.
C        Adjust capacity credit up 10% for T&D losses from regular capacity
C        to customer. (Not nec. same as NDT TDloss read above, since PV's
C        are locally distributed generation.
C        -----------------------------------

         maxload1(11) = 0.
         maxload2(11) = 0.
         maxload3(11) = 0.
         do i = 1,10
            maxload1(11) = maxload1(11) + maxload1(i)
            maxload2(11) = maxload2(11) + maxload2(i)
            maxload3(11) = maxload3(11) + maxload3(i)
         end do
         maxload1(11) = maxload1(11)/10.
         maxload2(11) = maxload2(11)/10.
         maxload3(11) = maxload3(11)/10.

C        Increase capacity credit by 10% overall system TD loss
         capcredit  = (maxload1(1) - maxload3(1))*(1.10)
         avecapcred = (maxload1(11) - maxload3(11))*(1.10)
         capfac     = anngen/(ndunitcap*8760)
         annVOM     = anngen*VOM/100.          ! MWh*cent/kWh/100 = k$
         storfrac   = annstor/anngen

         write(6,*)
         write(6,350)
350      format('Yr  Max1    Max2    Max3  CapCred  AnnGen  CF    VOM-k$
     1   AnnStor  StorFrac')
         write(6,360) ldyr1(0),maxload1(1),maxload2(1),maxload3(1),
```

```
     1                capcredit,anngen,capfac,annVOM,annstor,storfrac
      write(6,360) ldyr1(0),maxload1(11),maxload2(11),maxload3(11),
     1                avecapcred
360   format(I2,5F8.0,F6.3,2F8.0,F8.3)

400   continue
      go to 700


C     Stop - End or error reading data.
C     ---------------------------------

600   write(*,*) 'End or error reading data.'

700   continue

      close(03)
      close(04)
      close(05)
      close(06)

      stop
      end
```