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NEBRASKA POWER ASSOCIATION
Statewide
Resource and Transmission Planning Study
1991 - 2010

MAY 1991

NEBRASKA POWER ASSOCIATION
STATEWIDE
RESOURCE AND TRANSMISSION PLANNING STUDY
1991 - 2010

MAY, 1991

Prepared for:

Nebraska Joint Planning Subcommittee

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ACKNOWLEDGEMENTS

The preparation of this report was a cooperative effort among Nebraska utilities. Various departments within these utilities made major contributions to this report. Special acknowledgement is given to OPPD and its planning personnel for generously sharing their manpower and computer resources in this extensive computing project.

The increased emphasis on demand-side management resulted in participation by rates, load forecasting, load research, and marketing personnel from these utilities other than the Task Forces. Specifically, input from Phil Euler (LES), Damon Castrop (OPPD), and Larry Ciecior (OPPD) was very useful.

Likewise, in developing environmental costs and reviewing discussion the assistance of Ron Stoddard (LES), Roger Luhring (NPPD), and Bill Neal, (OPPD) was very important.

The Task Forces would also like to thank Connie Kramer (NPPD) for typing the many revisions to this document.

EXECUTIVE SUMMARY

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This 1991 Statewide Resource and Transmission Planning Study (Study) is prepared by the Nebraska Power Association for the Nebraska Power Review Board in accordance with Nebraska Statute 70-1025. In addition to determining generation and transmission expansion plans, the Study includes substantial evaluation of Demand-Side Management (DSM) options and environmental impacts. As such, the plan is a least-cost plan considering utility, customer, and environmental costs. The reporting period for these integrated plans is twenty years, from 1991 to 2010.

Electrical load growth in Nebraska has slowed from the 5.7% per year level in the 1970's to 1.2% per year in the 1980's. This slowdown was due to reduced economic growth, customer conservation, and utility-customer DSM programs such as irrigation load control. Load forecasts have declined accordingly. Most recently, the 20-year load forecast in this 1991 Study is for 1.7% growth per year whereas, in the 1986 Study, 2.1% per year was assumed. Consequently, forecasted needs for new supply-side generation facilities have declined as load forecasts have declined and DSM options are implemented. The last major generation resources were installed in 1982 to serve the electric energy requirements of Nebraska customers. These were Gerald Gentleman Unit #2 (Sutherland), a share of Laramie River Station (Wyoming) and Platte Generating Station (Grand Island) totalling 931 MW.

The Integrated Base Resource Plan (Integrated Base case) developed in this Study indicates that, from a statewide perspective, new generating facilities can be delayed from the year 2000 to 2002 by implementing selected DSM options. However, individual utilities will be addressing their near-term needs with purchases, DSM options, unit uprates, and/or installing generating facilities. The general NPA data and results of this Study will assist in those utility-specific analyses.

During the next twenty years, 76% of the new resource additions are required to serve increasing load obligations and 24% to replace retired generating capacity. All these factors are shown in Figure 1 for the Integrated Base case. The peak load forecast of 1.7% growth per year is shown as the increasing dashed line before study DSM is included. The existing resources are shown by fuel type with the current predominance of coal facilities continuing.

The load-side 228 MW of DSM programs selected for the Integrated Base case--efficient residential heat pumps, industrial interruptible load, and commercial lighting--reduce the dashed peak load obligation line to the solid, increasing line throughout a phase-in period that starts in 1993. The generation-side DSM program selected--leased customer generation--is shown on the total capability line as 64 MW, beginning its phase-in in 1996. The retirement of generating capacity shows up in the declining existing capability line, most notably the retirement of Fort Calhoun Nuclear Station in 2008.

The new resources selected for the Integrated Base case are shown in more detail in Figure 2. These new resources include the 292 MW (228 MW load-side and 64 MW generation-side) of phased-in DSM options first, then two 160 MW installations of combustion turbines in 2002 and 2003, then the 600 MW Nebraska City Unit #2 coal option in 2005 (existing site), then another 600 MW coal unit at another site in 2008, and finally another 160 MW installation of combustion turbines in 2010. The 600 MW coal unit added in 2008 is baseload capacity required to replace Fort Calhoun Nuclear Station.

These new resources totalling 1812 MW through 2008 are less than the 3250 MW indicated as needed through 2008 in the 1986 Study. This reduction is significant considering that the Fort Calhoun retirement was not provided for in the 1986 figure but is in the 1991 Study figure.

The study methods used were quite successful. The lists of supply-side and demand-side options were each narrowed to find the best, most competitive alternatives through basic costing comparisons and thorough computer analysis. The computer program PROVIEW, a state-of-the-art resource expansion program, was the principal study tool. The DSM options were also tested one-at-a-time against the best supply-side-only plan. In the final computer runs, an optimal integrated plan was selected for each base and sensitivity case combining the best supply-side and demand-side options. All computer runs included relevant utility, customer and environmental cost data. All utility costs were included while only customer cost differences between cases were necessary. The environmental costs included the installation and operating costs to control the impacts and an allowance for uncertain future environmental costs.

The principal conclusions of the Study are:

1. The order of resources selected over the 20-year period is:
   - demand-side management
   - natural gas-fired combustion turbines
   - large coal units
   - more combustion turbines

2. Nebraska City Unit #2 is the first coal unit selected and is chosen in 2005.

3. Some DSM resources are selected in all integrated base and sensitivity cases. The 292 MW of DSM selected in the Integrated Base case included 64 MW of leased customer generation, 74 MW of industrial interruptible load, 59 MW of efficient heat pumps, and 95 MW of commercial lighting.

4. The 292 MW of DSM options selected eliminate the need for 160 MW of combustion turbine capacity and provide one-year delays each in the need for two 160 MW combustion turbine installations and for the 600 MW Nebraska City Unit #2. The estimated benefit associated with these DSM activities is $299 million (1990 present value), a 1.3% reduction, evaluated from a total cost perspective factoring in customer effects and environmental considerations.

5. Installing the DSM resources slightly increases emissions because they delay the installation of new coal units which have lower emissions than the existing units. Nevertheless, the existing Nebraska coal facilities

have relatively low emission rates because of past investments in emission control and the use of low-sulfur Wyoming coal.

6. More than 20% of the cost to install and operate future coal units is dedicated to environmental protection. Such new coal units will reduce utility emissions by partially displacing generation produced by existing units.

7. To the extent possible, the effects of the Clean Air Act Amendments of 1990 are incorporated into all plans studied. Detailed regulations are still forthcoming. The resulting Integrated Base Resource Plan appears to meet the intent of the Clean Air Act Amendments of 1990.

8. The HR 4805 Carbon Tax sensitivity case results in the highest total cost for Nebraska ratepayers. The added cost is $3.18 billion (1990 present value), a 13.7% increase over the Integrated Base case. However, CO_2 emissions are not reduced because the tax does not result in a change to the expansion plan.

9. The 250 MW coal unit options at existing sites are not selected in the 20-year reporting period. However, these options are relatively competitive and remain good options for individual utilities.

10. The transmission additions required are significantly less than indicated in previous studies because of reduced load growth, application of DSM, and installation of combustion turbines prior to baseload units.

These conclusions are in general agreement with current planning activities at individual NPA utilities. The work represented by this Study has been and will continue to be used by the NPA utilities in developing their integrated resource plans.

FIGURE 1
INTEGRATED BASE CASE LOAD AND CAPABILITY

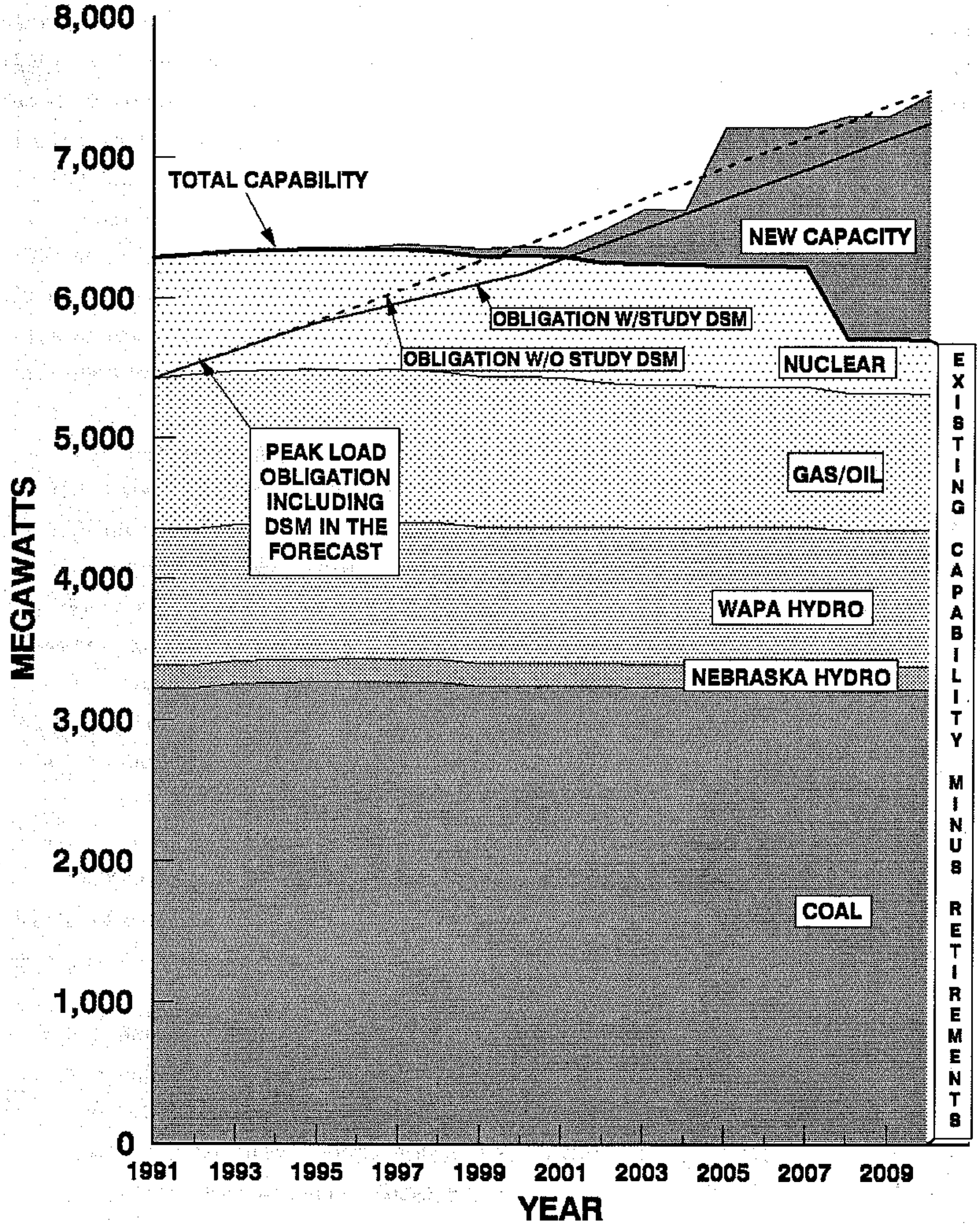

FIGURE 2

INTEGRATED BASE CASE RESOURCE ADDITIONS

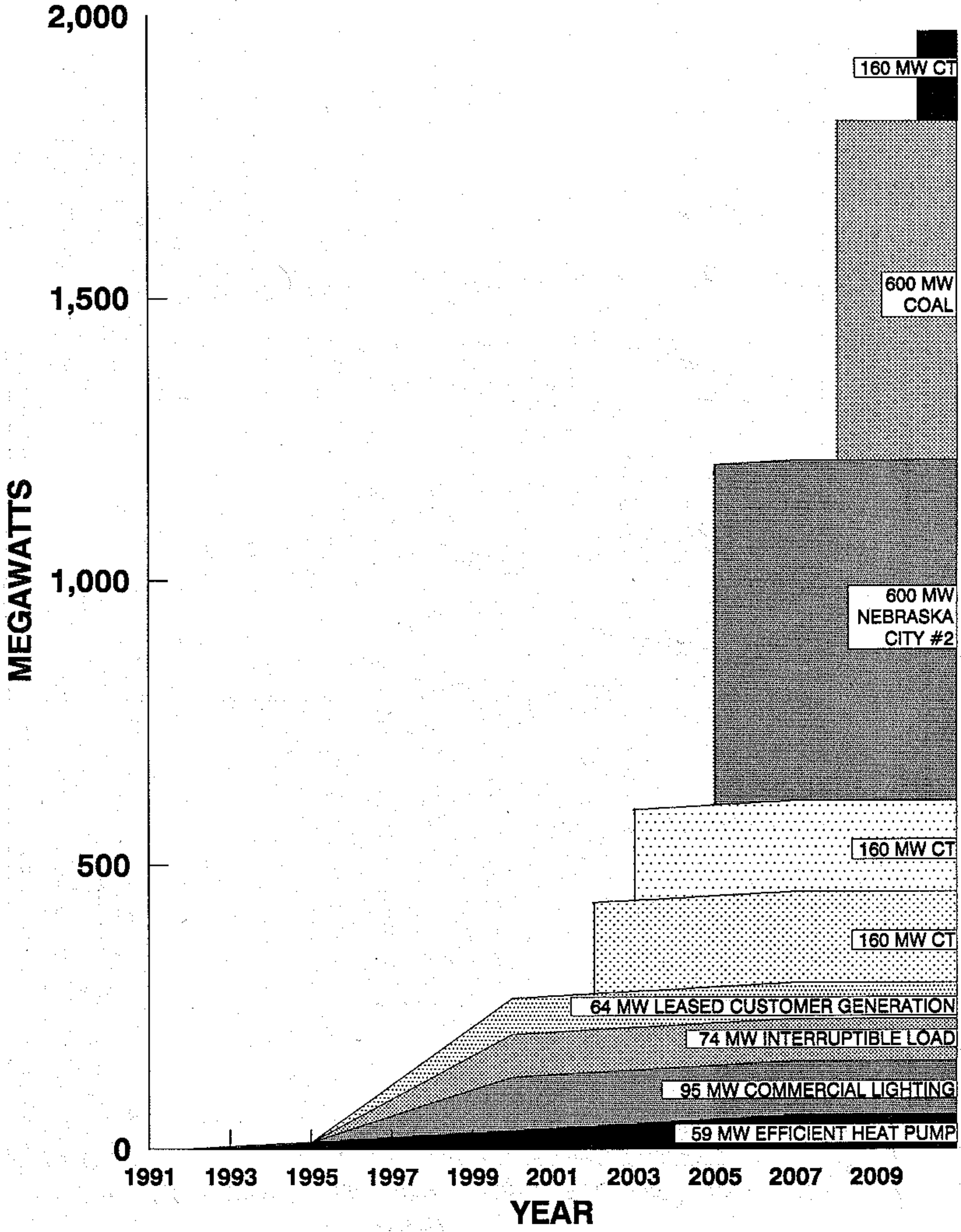

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TABLE OF ABBREVIATIONS

A&G	- Administrative and General
BACT	- Best Available Control Technology
BEPC	- Basin Electric Power Cooperative
CAES	- Compressed Air Energy Storage
CC	- Combined Cycle
CO_2	- Carbon Dioxide
CT	- Combustion Turbines
DEC	- Department of Environmental Control
DSM	- Demand-Side Management
EER	- Energy Efficiency Ratio
EIS	- Environmental Impact Statement
EPA	- Environmental Protection Agency
EPRI	- Electric Power Research Institute
FGD	- Flue Gas Desulfurization
GWh	- Gigawatt-hour, 1,000,000 kWh
IGCC	- Integrated Gasification Combined Cycle
IPR	- Iowa Power, Inc.
IPTF	- Integrated Planning Task Force
kW	- kilowatt
kWh	- kilowatt-hour
LDC	- Load Duration Curve
LES	- Lincoln Electric System
MAPP	- Mid-Continent Area Power Pool
MCFC	- Molten Carbonate Fuel Cell
MEAN	- Municipal Energy Agency of Nebraska
MMBtu	- Millions of British Thermal Units, a unit of heat
MSW	- Municipal Solid Wastes
MWH	- Megawatt-hour, 1000 kWh
NAAQS	- National Ambient Air Quality Standards
NEPA	- National Environmental Policy Act of 1969
NMPP	- Nebraska Municipal Power Pool
NO_x	- Nitrogen dioxide or oxides of nitrogen
NPA	- Nebraska Power Association
NPIC	- Nebraska Power Industry Committee

NPPD	- Nebraska Public Power District
NPRB	- Nebraska Power Review Board
NPV	- Net Present Value
NRC	- Nuclear Regulatory Commission
NSPS	- New Source Performance Standards
O&M	- Operation and Maintenance
OPPD	- Omaha Public Power District
PSD	- Prevention of Significant Deterioration
P.W.	- Present Worth (or Present Value)
SCR	- Selective Catalytic Reduction
SO_2	- Sulfur Dioxide
Tri-State	- Tri-State Generation and Transmission Association
TSP	- Total Suspended Particulate
WAPA	- Western Area Power Administration

TABLE OF DEFINITIONS

(as used in this report)

Baseload Capacity: Capacity operated at a high capacity factor to meet electrical loads that occur year-round and typically characterized by high investment and low energy costs.

Best Available Control Technology (BACT): The control technology that must be used by new or modified sources in clean air Prevention of Significant Deterioration areas.

Capacity Factor: In percent, the capacity factor represents the average output or utilization level of capacity. That is, the amount of energy that was produced by a generating unit in a given period, such as a year, divided by the product of the unit's capability times the number of hours in that same period, all times 100.

Carbon Dioxide: A gas emitted by the combustion process of carbon-based fuels.

Demand: The average rate at which energy is delivered during a specified time, usually 60 minutes, expressed in kilowatts.

Demand-Side Management (DSM): EPRI defines Demand-Side Management as "The planning and implementation of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape...i.e., changes in the time pattern and magnitude of a utility's load."

End-Effects Period: The 15-year time period from 2020 to 2034 for which the analysis makes a simplified evaluation of the relative values of expansion plans after the planning period. Also see Section 3.0.

Energy: The ability to do work such as heating homes, running lights, etc., expressed in kWh.

Energy Efficiency Ratio (EER): A ratio calculated by dividing the cooling capacity of an air conditioner or heat pump by the electrical power input at any given set of rating conditions expressed in Btu per watt-hour.

Environmental Impact Statement (EIS): The document that must be prepared by the lead federal agency to satisfy the requirements of NEPA, and which becomes a major decision document for federal decision-makers involved in generating unit installation.

Expansion Plan Reporting Period: The 20-year time period from 1991-2010 for which the expansion plan results are reported.

Externality: A cost implication of a decision that is not borne by the decision-maker.

Flue Gas Desulfurization: A method using lime, limestone, or a similar substance to remove sulfur dioxide from power plant exhaust gases. The required equipment is commonly referred to as a scrubber.

Heating Seasonal Performance Factor (HSPF): The total heating energy output of a heat pump during its normal annual usage period for heating divided by the total electric energy input during the same period, expressed in Btu per watt-hour.

Intermediate Capacity: Capacity operated at a moderate capacity factor to meet electrical loads that occur 20-40% of the time during the year and typically characterized by moderate investment and energy costs.

Least Cost Plan: For a given future outlook, the set of demand-side and supply-side resource additions that minimize the total cost considering all areas. In this Study, the Base Integrated Resource Plan is the least cost plan considering all utility costs, primary customer costs and primary environmental costs.

Load Factor: Load factor is the average demand during a given period divided by the peak demand.

New Source Performance Standard (NSPS): National emission standards for conventional pollutants pertaining to specified source categories for new and modified generating sources.

Nitrogen Dioxide or Oxides of Nitrogen (NO_x): Pollutant emitted by the combustion process, i.e., the burning of any fossil fuel.

Particulates: Particles of dust or ash leaving the plant exhaust stack or plant site.

Peaking Capacity: Capacity operated at a low capacity factor to meet loads that occur only about 10% or less of the time and typically characterized by low investment and high energy costs.

Planning Period: The 30-year time period from 1990 to 2019 for which detailed computer analysis is performed in the optimization or simulation of resource expansion plans. Also see Section 3.0.

Prevention of Significant Deterioration (PSD): Designation used for an area in compliance with National Ambient Air Quality Standards (NAAQS).

Reliability: The likelihood that the power system, including DSM resources and generation, transmission, and distribution facilities, will be able to deliver power to the customers when it is needed.

Resource (Power Resource): A utility means of satisfying the electricity needs of its customers. A supply-side power resource is a generating unit or power purchase and a demand-side power resource is a utility program or action that involves the customers in modifying their own needs. Usually, DSM programs are on the load side. However, in this study, leased customer generation is designated as DSM because the generation belongs to end-use customers.

Run: The process of executing a computer program to produce calculation results or other output for the Study.

Selective Catalytic Reduction (SCR): A method for removing oxides of nitrogen from power plant emissions by passing the exhaust gases through a catalyst bed.

Study Period: The 45-year time period from 1990 to 2034 that encompasses the planning period and the end-effects period. Also see Section 3.0.

Sulfur Dioxide (SO_2): Pollutant emitted by the combustion process of fuels containing sulfur or compounds of sulfur.

Supply-Side: The production or supply of electricity by a utility for its customers through generation or purchase resources.

Total Cost Evaluation Criteria: The Study criteria for ranking expansion plans based on the minimum total quantifiable cost, when viewed from the combined perspectives of the utility and its customers.

SECTION 1
INTRODUCTION

1.0 Introduction

The Joint Planning Subcommittee was officially formed in 1977 as a subcommittee of the Industry Task Force and has been continued under the Nebraska Power Association (NPA) formed in 1980. Prior to formation of the Industry Task Force, coordinated long-range generation planning studies were completed by the Nebraska Power Industry Committee (NPIC).

The NPA Joint Planning Subcommittee established a Joint Planning Task Force in 1980 primarily to prepare a Statewide Generation Planning Study. The first NPA Statewide Generation Planning Study was completed in March of 1981 for the period 1980-2009. The associated bulk transmission study was completed in January, 1982. Generation and transmission studies were subsequently updated in 1982, 1984 and 1986. The name of the Joint Planning Task Force was changed to Integrated Planning Task Force (IPTF) to more accurately portray that their work integrates the loads and resources of all Nebraska utilities, integrates demand- and supply-side resource options, and integrates resource and transmission plans.

The Integrated Planning Task Force began work on this Statewide Resource and Transmission Planning Study 1991-2010 (Study) in December, 1988 at which time an initial work schedule was given to the Nebraska Power Review Board. Load and capability forecasts have also been provided on an annual basis. The Study is being completed at the request of the Nebraska Power Review Board in accordance with the requirements of Nebraska Statute 70-1025 included as Appendix A.

The Integrated Planning Task Force considered already existing and committed statewide generation capability together with state-of-the-art developments in both supply and demand-side resources in planning for future growth needs of the state. This year's study puts additional emphasis on a comprehensive evaluation of demand-side options and also incorporates environmental considerations into the Study in developing a statewide least cost plan.

The Joint Planning Subcommittee also established the Transmission Task Force, assigning to it the responsibility of exploring the associated statewide transmission requirements for various generation alternatives. The Transmission Task Force helped the Integrated Planning Task Force include transmission-related costs in the base plan identified in the Study.

It is important to keep in mind that with an analysis involving more than one utility, the results will have varying impacts on the individual utilities. The financial benefits of joint construction, demand-side management, or conservation programs resulting from a study of this nature may not be available to all the individual utilities and their customers to the same degree. Because of this, individual utilities may not be able to economically justify participation in some joint projects and further, some demand-side options may appear to be beneficial for the state but may not be beneficial for some individual utilities and their customers.

This Study, which is intended to be long-range, has been undertaken by the Omaha Public Power District (OPPD), the Nebraska Public Power District (NPPD), the Lincoln Electric System (LES), the Nebraska Municipal Power Pool/Municipal Energy Agency of Nebraska (NMPP/MEAN), and Tri-State Generation and Transmission Association (Tri-State). Coordination for this Study has enabled these utilities to exchange planning information and data. The result of this exchange has been a refinement of data and procedures which will assist in the accuracy of future generation planning for the state as a whole and for individual utilities.

This report is intended to be somewhat tutorial in nature, as an aid to understanding in addition to giving specific study results. The material is presented in an order similar to that in which the Study itself proceeded.

SECTION 2

PURPOSE AND OBJECTIVES

2.0 Purpose and Objectives

2.1 Purpose

The purpose of the Statewide Resource and Transmission Planning Study is to identify and evaluate alternative resource expansion plans and associated transmission requirements based on the coordination of generating unit additions by all electrical utilities in the State of Nebraska in order to provide a reference for coordinated long-range generation, conservation and demand-side planning for the state. In accomplishing this purpose, the Study provides basic guidelines and reference material to be used by all the electric utilities in the state.

2.2 Objectives

1. Evaluate the options available to provide for future load from the standpoints of economics, environmental considerations, and risk (e.g., reliability, fuel availability, and state of technology).

2. Develop a plan for meeting future electric load growth incorporating supply- and demand-side options.

3. Develop an associated bulk transmission plan.

4. Encourage maximum cooperation and coordination among all agencies involved in providing electric service in the state, utilizing the expertise of individual utilities.

5. Provide timely information on power supply planning matters to the Nebraska Power Review Board.

6. Develop data and produce results in a format which can be used by other Task Forces within the NPA.

SECTION 3

METHODOLOGY, TOOLS, AND SIZE OF STUDY

3.0 Methodology, Tools, and Size of Study

This chapter reports on the "mechanics" of doing the Study. Power resource planning studies are important because the facilities requiring the greatest capital investment by the power industry and its ratepayers are those associated with the generation resources. Large investments can also be made in demand-side options and are spread over large numbers of installations. In addition to the costs involved, the utilities and the public are interested from the standpoints of environmental effects and reliability of service.

In a joint study of this nature, the loads and resources of all utilities involved are blended, or joined together. The load forecast for which resources are studied is the sum of the individual utility forecasts. The day-to-day pattern of the load in 1984, complete with its particular weather variations, is used as a representative initial shape of the future loads. Necessary scaling adjustments are made to this load data to accommodate load growth and trend changes in load factor, as energy is expected to grow differently than peak demand.

This long-range study considers the total projected statewide loads for the period 1990-2019, a planning period of 30 years. The year 1990, even though it has passed, is part of the planning (or projected) period because load modeling data was finalized in 1990 before actual 1990 loads were known. The significance of the planning period is that the computer program performs the full optimization process over that period. End-effects are incorporated by having the computer program make certain cost calculations for an additional 15 years to 2034. After 2019, no load growth is modeled and the only resources assumed to need replacement are those resources that were selected by the computer program to begin with, and that have lifetimes expiring prior to 2034. Because the loads and resources are held constant in the end-effects period, no additional unit dispatching is required during that period. The year 2034 was selected so that a coal unit installed early in 2000 would be evaluated over its full life of 35 years. The combination of the planning period and the end-effects period is called the study period (1990-2034). The expansion reporting period is shortened to 1991-2010 to focus on the most pertinent findings relevant to Nebraska's resource alternatives.

Utilities today have many resources to choose from, both on the supply (utility) side and on the demand (customer) side. The first task is to determine which base plan of resource additions and replacements best satisfies the needs of the utilities and their customers as well as the public at large. The evaluation criteria in Section 4.6 is used to find that base plan. To do that, extensive judgement and computer analysis within the disciplines of engineering, economics, and environmental effects are employed. Most of the inputs to the analysis (e.g., economic growth, fuel prices, and interest rates) carry some degree of uncertainty as to future magnitudes. Because of this uncertainty, a sensitivity analysis is done to identify the impact of some of the major assumptions on future decisions concerning the base plan.

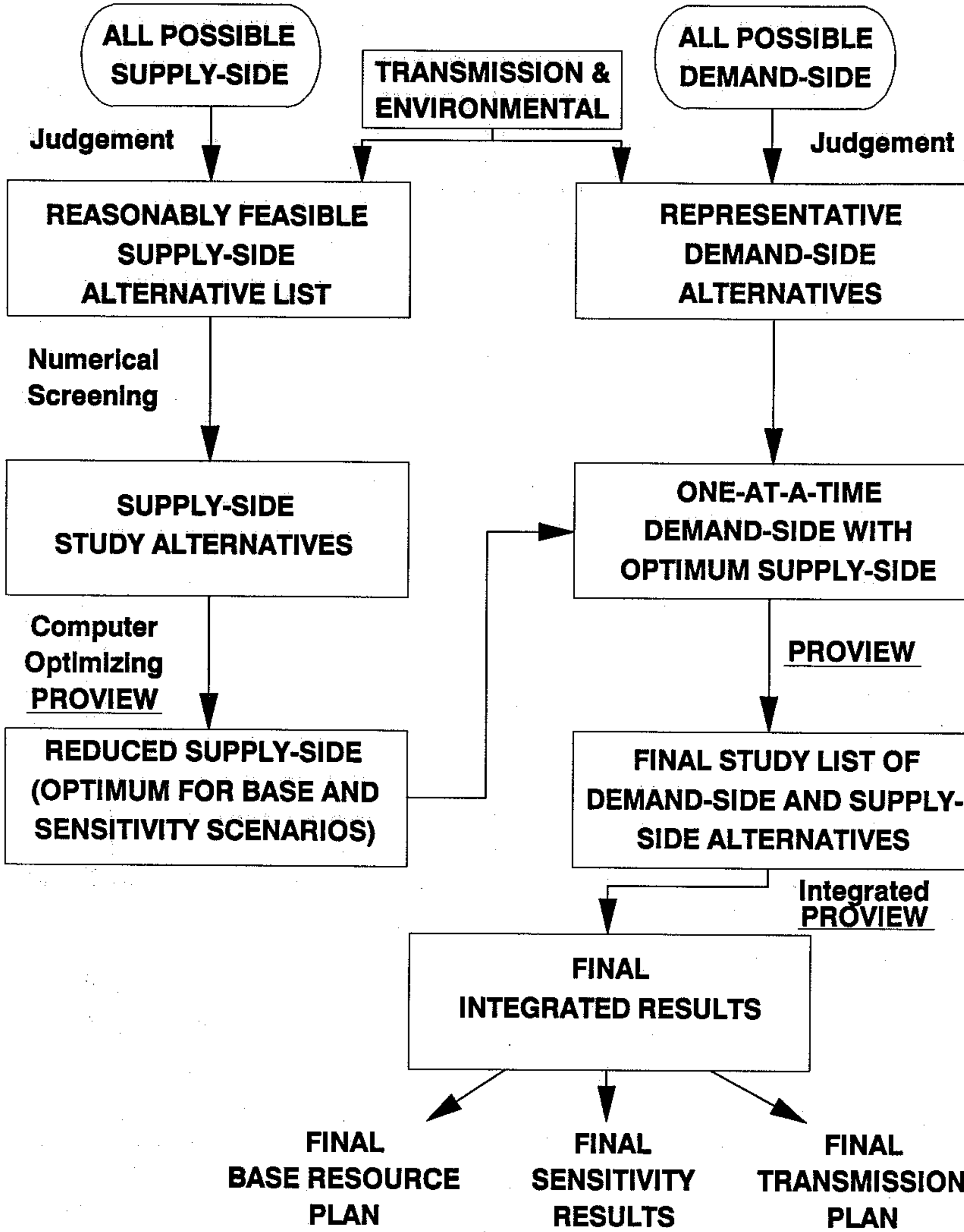
The rest of this chapter presents a flow chart of the study, information on the primary computer program used (PROVIEW), and a summary of the study effort involved.

3.1 Study Flow Chart Overview

Figure 3.1-1 shows the major steps of the Study in more detail than the study description given in Section 3.0. In Chapter 4, still more details are given concerning the individual steps of the Study. Here, in overview form, we can make the following observations in reference to the figure:

- The first step in dealing with either the many supply-side or demand-side options (but especially so on the demand-side), is to use experience and judgement in determining which options warrant being retained.

FIGURE 3.1-1
NPA STUDY OVERVIEW



- For the following selection process that deals with these initial lists of explicit alternatives, all quantifiable costs, including transmission and environmental, are considered.

- The list of supply-side alternatives is further shortened, first by numerical screening, a graphical comparison process described in Subsection 4.7.1, and then by expansion optimization runs using the computer program PROVIEW, described in Subsection 4.7.2.

- Next, each demand-side alternative that has been chosen as a strong representative for one of the EPRI load shape modification objectives is tested one-at-a time for competitiveness against the optimized supply-side list using PROVIEW. This process is described in the various subsections of 4.7.4.

- After saving the most competitive demand-side alternatives for further analysis, final PROVIEW optimization runs simultaneously consider all remaining demand-side and supply-side alternatives and produce integrated, optimized plans as described in Section 5.0. The preliminary, list-narrowing steps are necessary to reduce computation time to a manageable level. Thus PROVIEW examines only the best combinations of expansion alternatives rather than exhaustively searching through all possible combinations.

- The key results are the final Integrated Base Resource Plan (Integrated Base case), several resource plans responsive to sensitivity variations on major variables, and a transmission plan, all of which are described in detail in Chapter 5.

Although not shown on the flow chart in Figure 3.1-1, the data gathering and preparation activities are nonetheless some of the most time-consuming and important activities in the Study. Especially for demand-side options, the data requirements are quite voluminous, yet the data is not as available as for the more traditional supply-side options. Also, data for DSM options often is weather sensitive and results from other areas of the country are not necessarily transferrable.

3.2 PROVIEW Computer Program

The PROVIEW computer program is an expansion model. In the electric utility industry, the purpose of an expansion model is to determine the lowest cost sequence of resources that are needed to supply load growth and to replace existing units being retired during the study period. These resources can be either demand-side options or supply-side options. The terms, study period, planning period, end-effects, and reporting period are described and specified in Section 3.0.

For this Study approximately 3,600 MW of resources are needed during the planning period. Considering only supply-side resources, there are nine options of widely varying size available to PROVIEW in any given year. A 600 MW unit may be required just for one year's retirement of another large unit or it may satisfy six years of load growth. On the other hand, just one year's load growth may require five-20 MW advanced battery installations.

For each combination of resources in a given year, PROVIEW will calculate the energy dispatched, the fuel consumed, the environmental emissions, and the cost of operating the existing and new resources in meeting the load in that year. This is a lengthy computation in that it considers through mathematical modeling all possible combinations of units that could be used to supply the load. It also considers that at certain times, various units may not be available due to unexpected forced outages or being shut down for maintenance. In order to find the lowest cost combination in a given year, the costs of all the possible combinations in that year need to be calculated. In trying to find the lowest cost plan (or optimal plan) for the entire planning period, all possible sequences of combinations need to be considered.

If no restrictions were put upon the sequence of combinations that could be used to meet the load growth, there would be a seemingly infinite number of possible plans presented by the nine supply-side resource options. This does not even consider the additional possible plans that would be created by the addition of demand-side options. Even a high-speed, state-of-the-art computer could run for a very lengthy time attempting to complete all of these calculations. The program is able to reduce the number of states or combinations evaluated for the supply-side options to about 3,000. This is done by developing input constraints using common sense, natural physical restrictions, judgement on which combinations have a reasonable chance of being economical, and other reasonable methods of restricting the number of combinations and sequences that are studied. There is still a significant computational effort remaining which requires an overnight run on a state-of-the-art computer.

3.2.1 Selection of PROVIEW

The Integrated Planning Task Force reviewed eight different models with potential for use in the Study. These models, with the supporting firm shown in parentheses, are as follows: AGP (Westinghouse), PROVIEW (Energy Management Associates), EGEAS (EPRI, Stone and Webster), DS-MANAGER (Electric Power Software), LMSTM (EPRI), COMPASS (Synergic Resources Corp.), MIDAS (EPRI), and UPLAN (Utility Software and Modeling Center). Brief reviews were done of all models and characteristic evaluations were done for PROVIEW, DS-MANAGER, EGEAS, MIDAS, and LMSTM. PROMOD (EMA), used by OPPD, and AGP, used by NPPD, were also discussed along with the five models reviewed in detail.

In the interest of time it was decided to place a high priority on the existing familiarity of the utilities with the models. The models that NPA members are most familiar with are PROVIEW, EGEAS, PROMOD, and AGP. After further evaluation PROVIEW was selected as the preferred model. The primary reasons for selection of PROVIEW were: 1) OPPD's knowledge and experience with the model, 2) the model's compatibility with PROMOD data used in the last NPA study, and 3) its ability to handle demand-side management program analysis. Both PROMOD and PROVIEW are widely used in the electric utility industry and held in high regard. In addition, some consulting support would be available from Energy Management Associates if needed.

3.2.2 Technical Aspects of PROVIEW

Users divide the data for PROVIEW into two basic sections: 1) Existing utility system and 2) potential supply-side or demand-side management options (planning alternatives). The existing system data covers information on existing units, transactions, fuels, general assumptions and the existing load forecast data. Data on existing units include such information as operating characteristics, operation and maintenance costs, fuel costs, and emission rates.

The planning alternatives section of PROVIEW data contains similar information as the existing utility section on the characteristics of units. In addition the construction cost and the cost of money for financing new units are included. Demand-side management programs require data such as demand and energy reduction, load patterns by type of weekday and by month, number of customers expected to participate in a program, and capital and operating and maintenance costs of the program. General parameters included in the planning alternatives section are constraints on the addition of resources, reliability constraints for the system, forecasted discount rate, study period, and planning period.

PROVIEW calculates the capacity requirements to meet the load forecast and reliability constraints. Then supply-side options and demand-side management options are added in different combinations to meet the deficit between the load plus reliability requirements and the capability of existing resources. When supply-side options are selected, they are dispatched along with the existing resources to meet load requirements. When DSM options are selected, the load data is modified on a monthly basis using the load pattern of the demand-side option for a typical week. The modified typical week load data for each of the twelve months is accumulated on an annual basis. This load data is sorted numerically by size. The combined load data is plotted to show the number of hours during the year that each load level is met or exceeded. This is known as a load duration curve (LDC).

Table 3.2.2-1 shows the most common outputs available from PROVIEW for review by the user. The outputs are shown for three different periods. The study period includes the planning period and the end-effects period.

The data indicated in Table 3.2.2-1 are retained for each separate plan. The sequence and combination of additions by year for each plan is one of the primary reports. The plans are ranked according to an objective function. This objective can be, for example, to minimize total cost, to minimize average study period rates, or to minimize customer class rates. Plans in this Study were ranked by minimizing the total cost, that is considering utility costs, customer costs, and environmental costs.

3.2.3 Performance and Satisfaction with PROVIEW

In general PROVIEW has worked well in developing expansion plans for both demand-side and supply-side options. The flexibility of the load forecast adjustment module, the program's ability to handle demand-side options, and the amount of reporting detail retained on plans have been particularly useful.

3.3 Study Effort

This joint study required two and one-half years to complete and is the most comprehensive yet done by the NPA. Fifteen people played fairly active roles and perhaps twenty others provided technical support. This effort was accomplished by forty meetings and over 10,000 manhours. Computer time amounted to 250 hours of central processing unit (cpu) time on an IBM Model 3090 mainframe computer. The methodology of the Study was expanded over previous studies to more fully consider environmental effects and customer costs. Research into some of these areas involved contacting consultants and industry experts at the Electric Power Research Institute. It is hoped that this effort meets the needs of the Nebraska Power Review Board. The information gathered has been and will continue to be useful as a planning reference for the utilities involved.

TABLE 3.2.2-1 Outputs Available from the PROVIEW Computer Program			
	Study Period	**Planning Period**	**End Effects Period**
Rank of the Plan	X	X	
Total Electric Revenue Requirements	X	X	X
Customer Rates	X	X	
Customer Costs	X	X	X
Total Costs	X	X	X
Electricity Sales	X	X	X
Capacity Additions by Year		X	
Emissions (SO_2, CO_2, NO_x) by Year by Unit		X	
Fuel Use by Year by Unit		X	
Energy Use by Year by Unit		X	
Fuel Use by Type		X	
Reserve Margin		X	
Expected Emergency Energy		X	
Expected Loss of Load Hours (LOLH)		X	

SECTION 4
ASSUMPTIONS AND PRELIMINARY ANALYSES

4.0 Assumptions and Preliminary Analyses

This chapter describes in some detail the major assumptions relevant to the Study and also summarizes the preliminary analytical steps leading up to the final step, the integrated PROVIEW analyses. Chapter 5 describes the final analyses and results. In particular, this chapter covers work done before the activities depicted in Figure 3.1-1 (e.g., load forecasts) down through the PROVIEW runs of "one-at-a-time" demand-side alternatives competing with the reduced list of supply-side alternatives.

4.1 Load Forecasts

Two of the most significant inputs to any resource planning study are the forecasts of peak demand and energy. The Study focuses on the base (expected) forecast level at which actual loads are thought to have a 50% probability of exceeding the base level and a 50% probability of not reaching the base level. Two sensitivity cases examine the effects of more extreme high and low load growth scenarios. These high/low load extremes are believed to represent respectively forecast levels at which there is a 15% probability that the load could be higher and a 15% probability it could be lower.

The purpose of this section is to summarize the load forecasting methods used and the results obtained by the NPA utilities.

4.1.1 Load Forecasting Methodology

Load forecasting is a study process of complexity similar to the resource planning study itself. In December 1985 the NPA utilities presented a report to the Nebraska Power Review Board on "Load Forecasting Methodologies and Procedures Used by the Nebraska Utilities". That report contains further tutorial and detailed information on the methods used by the NPA utilities. The report is fairly current, although the utilities continue to refine and update their models and techniques.

To varying degrees, all of the following load forecasting techniques are used by NPA utilities:

- **trending (or time series),** wherein forecast values are functions only of past values and/or time

- **econometric models,** wherein forecast values are functions of economic and demographic variables such as population, income, etc.

- **end-use models (or engineering models),** wherein forecast values are functions of the amount (or stock) of energy-using appliances, equipment, or devices, and the amount of energy each appliance or device uses

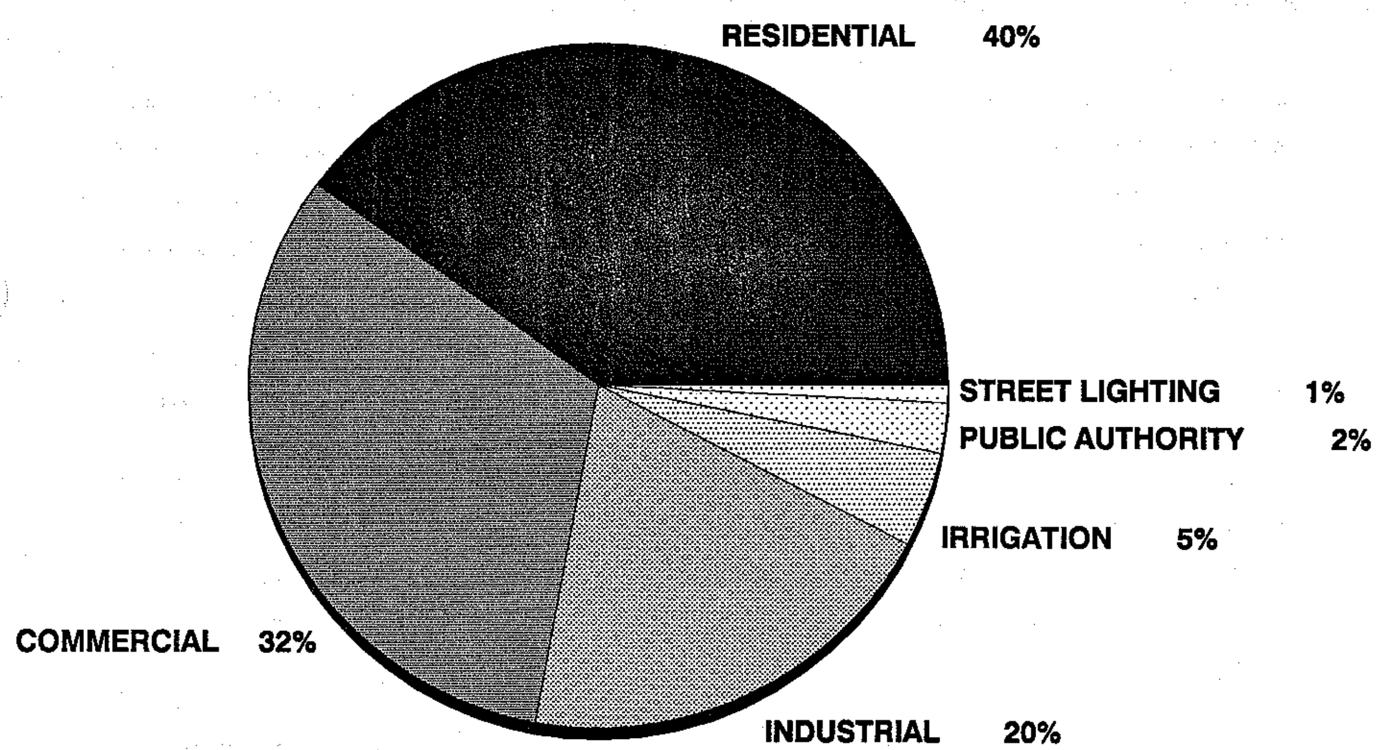
- **hybrid models,** which are most often combinations of the models described above, e.g., the use of econometric models to forecast an end-use component of load such as appliance saturations.

More than one forecasting technique will likely be used by each utility because it must create models for each class of load. Energy is usually broken down into several classes of load, e.g., residential, commercial, industrial, irrigation, public authority, and street lighting. Such a breakdown for Nebraska is shown in Figure 4.1.1-1. The customers within each class of load usually have common traits and associated data, which may be best modeled using a particular forecasting technique. The forecasts for the separate classes of load are combined and system losses are included to estimate the system inlet requirements at the generating station level. In order to facilitate other studies, such as resource planning, the load forecast will include energy requirements on an annual, monthly, and, quite often, an hourly basis for thirty years into the future.

The other general type of load forecast is the system peak demand forecast which has the purpose of determining the hourly loads at extreme times of the year, principally summer and winter. However, monthly peaks for the other months are typically developed also for use in planning studies.

FIGURE 4.1.1-1

RETAIL ELECTRIC ENERGY SALES IN NEBRASKA BY CLASS



Both energy and peak demand have been found to be dependent on many factors. Some of the most important factors for Nebraska utilities are population, family size, employment, income, general price indices, interest rates, fuel prices, electricity price, agricultural commodity prices, crop yields, number of appliances, types of appliances, appliance efficiency, conservation, weather, and customer incentive programs on the demand-side.

In summary, the above factors influence load growth which is one of the main influences on the timing and type of resources needed. The higher the load forecast, the sooner the resource additions are needed. The higher the energy forecast (relative to the peak forecast), the greater the need for baseload resources and vice-versa. Resources to be added may be supply-side, such as generation, or demand-side, such as load reduction programs.

Demand-side programs already installed or committed and their effects are factored into the original load forecast. Additional demand-side alternatives are investigated in the resource planning study and, in so doing, complicate the study by creating different load conditions to be met by the supply-side resources.

4.1.2 Load Forecast Results

The comparison of the load forecasts to the resource capability is usually accomplished in a tabular format called the load and capability report. This is presented for the base load forecast in Appendix B. This type of information is filed with the Nebraska Power Review Board by NPA on an annual basis.

The summer season (and annual) system peak demands in MW for each of the NPA coordinating utilities and for the statewide total are shown at the top of page B-1 for the study period of 1990-2019. Note at the right-hand side, the individual forecast growth rates range from 0.46% per year to 2.09% per year with the statewide average total being 1.61% per year.

The MAPP Agreement requires member utilities to maintain 15% reserve generation capacity above their native load obligation. The load and capability report can be thought of as a spreadsheet calculation of the makeup of the utility's plan for meeting that reserve and load obligation. For firm sales and purchases (page B-1), the seller maintains the 15% reserve requirement. In a participation sale (bottom of page B-3), the buyer is responsible to back up the capacity with 15% reserves.

The "bottom-line" of the load and capability report is the statewide surplus/deficit capacity line (page B-2) calculated as:

Resources	(page B-2)
+ Participation Purchases	(page B-3)
- Participation Sales	(page B-3)
+ 1.15 * Firm Purchases	(page B-1)
- 1.15 * Firm Sales	(page B-1)
- 1.15 * Native System Peak Load	(page B-1)
Surplus Capacity	(page B-2)

When capacity goes from surplus to deficit, note the year 2000 on page B-2, resources need to be added. This is called the year of need for capacity (demand- or supply-side resources).

The forecasts in Appendix B are the current ones used in the Study. They are also very nearly the same as those filed with the Nebraska Power Review Board in June, 1990. Some demand-side programs are already factored into the load forecasts, e.g., extensive irrigation load management, some water heater and air conditioner load control, space heating and water heater incentive programs, conservation, and some interruptible industrial and municipal loads.

Load forecasts have come down significantly from the seventies and early eighties and currently are fairly steady in the 1.5-2.0% per year range. Table 4.1.2-1 lists some growth rates for comparison between this Study and the 1986 study.

TABLE 4.1.2-1 Statewide Summer Peak Demand Forecasts		
	20-Year Compound Growth Rate (% Per Year)	
	1986 Study	1991 Study
High	2.60%	2.36%
Base	2.08	1.73
Low	1.57	0.99

Table 4.1.2-1 shows that the base load forecast used in this Study is quite similar to the low load forecast in the previous 1986 study. As a result of this lowering of the forecast, the previous capacity need date of 1998 has slipped to the year 2000.

Table 4.1.2-2 provides more detail on the load forecasts used in this Study and shows that:

- summer peak demand is expected to grow at 1.0-2.4% per year

- energy requirements and winter peak demand are expected to increase slightly more rapidly than summer peak demand

- the resulting increase in load factor is expected to be 3-4%

- the year that additional capacity is needed varies from 1998 to 2007 depending on the load forecast

TABLE 4.1.2-2 Statewide Load Forecast Details - 1991 Study			
20-YEAR VALUES	**LOW FORECAST**	**BASE FORECAST**	**HIGH FORECAST**
Summer Peak Demand (% per yr)	0.99%	1.73%	2.36%
Winter Peak Demand (% per yr)	1.20%	1.90%	2.54%
Annual Energy (% per yr)	1.27%	2.03%	2.76%
1990 Load Factor	48.9%	49.0%	49.1%
2010 Load Factor	51.8%	52.1%	53.1%
Capacity Need Date	2007	2000	1998

All individual utility peak loads are studied as if they are coincidental. That is, all utilities are shown as peaking in the same hour on the same day. This procedure agrees with MAPP planning methods so it is appropriate from the capacity planning standpoint. On the energy cost analysis side, assuming coincidence is slightly conservative, because in a given year there may be some diversity in the timing of peak loads. Generally, however, there is a great deal of coincidence because of the usual high correlation of hot and dry weather across the state. This was the case in 1984, the year used in this Study for a starting load pattern. A small amount, approximately 101 MW, of the loads reported by NMPP/MEAN, NPPD and Tri-State in western Nebraska are not in MAPP but are in the Western Systems Coordinating Council.

During the 1980's the statewide summer peak demand grew by 1.21% per year, compounded annually, as shown in Table 4.1.2-3, while the population grew 0.054% per year using preliminary census data. Based on a University of Nebraska at Lincoln Bureau of Business Research report the expected population growth for Nebraska from 1991 to 2010 is 0.094% per year. Of course, the expectation is that urban areas will grow and rural areas will generally decline in population.

TABLE 4.1.2-3
Historical Nebraska Load Growth Rates

	1970	1980	1990	1970-1980 Compound Annual Growth Rate (% per yr)	1980-1990 Compound Annual Growth Rate (% per yr)
NPPD	938 MW	1720 MW	1727 MW	6.25%/yr	0.04%/yr
OPPD	860 MW	1348 MW	1652 MW	4.60%/yr	2.05%/yr
LES	250 MW	410 MW	538 MW	5.07%/yr	2.75%/yr
NMPP/MEAN	NA[1]	430 MW	483 MW	NA[1]	1.17%/yr
TRI-STATE	90 MW	242 MW	280 MW	10.40%/yr	1.47%/yr
STATEWIDE	2138 MW[2]	4150 MW	4680 MW	5.69%/yr[2]	1.21%/yr

[1] Not applicable because NMPP/MEAN was not formed at that time.

[2] Excluding independent municipals in 1970 and NMPP/MEAN loads in 1980 for comparative growth calculation.

The NPPD peak load growth rate for the eighties was significantly lower than the growth rates of other utilities as shown in Table 4.1.2-3. This is due in part to a significant move by NPPD customers to DSM with irrigation load control. NPPD expects this control has reached near-maximum participation rates so that future load growth will probably exceed the growth rate of the eighties.

4.2 Expected Availability and Costs of Existing Resources

Just as Section 4.1 examined the outlook for Nebraska loads, this section begins looking at the future of Nebraska's power resource situation. First, in this section, the existing resources are discussed and then later, starting in Section 4.7, future alternative additions are introduced for consideration in the Study.

4.2.1 Outlook for Existing Supply-Side Resources

A considerable amount of information is provided on the existing supply-side resources. Appendix C lists the existing supply-side generating units in Nebraska. Some of the capacity of these units is sold to utilities outside of Nebraska, e.g., one-half of Cooper Nuclear Station is sold to Iowa Power, Inc. In Appendix B, only the capacity available for Nebraska use is listed on page B-2 and the assumed capability status over the entire 30-year planning period is displayed. In summary, 88% of the existing Nebraska resources are assumed to still be operational twenty years from now. The assumed generation changes are listed by utility in Table 4.2.1-1.

TABLE 4.2.1-1
Changes in Existing Generation Assumed in the 1991 Study
(20-Year Values)

UTILITY	GENERATION CHANGE IN MW (2010 LESS 1991)	YEARS OF CHANGES (see p. B-3 for detail)
OPPD	-452 MW	1992, 1993, 2001, 2008
NPPD	-17 MW	1996, 2002, 2004
NMPP/MEAN	-144 MW	1993, 1998 and every year thereafter
LES	0 MW	1993, 1994, 1995, 1999
TRI-STATE	0 MW	---
TOTAL	-613 MW	

Seventy-eight percent (476 MW) of Nebraska's share of net retirements represented in Table 4.2.1-1 is made up of the retirement of Fort Calhoun Nuclear Station at the end of its operating license in 2008. Cooper Nuclear Station is assumed to retire at the end of an extended operating license in 2014. The remaining retirements are aging, smaller units distributed throughout Nebraska. The effect of these twenty years of generation changes can be seen in Figure 6.2-1.

It should be noted that Tri-State has an existing agreement for purchasing power supply exactly sufficient to cover future load growth. Tri-State's share of Nebraska load is shown as being exactly covered by a matching firm purchase on page B-1 with a resulting zero net effect on the statewide surplus/deficit capacity situation (page B-3).

As noted in Subsection 4.1.2, the need date for adding resources is determined by resources on hand, transactions involving the resources, reserve requirements, and native load. Table 4.1.2-2 shows that the statewide need date varies from 1998-2007, depending on load growth. The need dates of individual utilities vary earlier or later than those listed in the table. Discussions have been held between NPA utilities concerning the many options available for the near-term needs of utilities including the selling and buying of surplus capacity inside and outside of the state. Besides this implicit assumption about sharing capacity between NPA utilities, the Study also has an implicit assumption about sharing energy producing capability by virtue of PROVIEW's joint dispatch of the state's resources. Other options such as demand- and supply-side additions and uprating of existing capacity are all being investigated further by individual utilities. According to the load and capability reports assumed in this Study, the first years of capacity deficit (need dates) for each utility are as shown in Table 4.2.1-2.

TABLE 4.2.1-2
First Year of Capacity Deficit by Utility
(Base Load Forecast)

OPPD	LES	NMPP/MEAN	NPPD	TRI-STATE	STATEWIDE
1994	1994	2003	2010	N/A	2000

Nebraska utilities have in-place an excellent, low-cost mix of supply-side resources as shown in Figures 4.2.1-1 and 4.2.1-2 and Appendix D.

The supply-side resource capacity in Figure 4.2.1-1 includes purchases and excludes sales. Only Nebraska shares are included. Firm transactions are factored up by the 1.15 multiplier to account for the reserve backup. Although 17% of the capacity is fueled by natural gas or oil, it is important to realize from a cost standpoint that less than 1% of the energy is produced from these higher cost gas/oil resources as shown in Figure 4.2.1-2.

Appendix D shows the production cost advantage of the coal- and nuclear-fueled energy over the gas- and oil-fueled energy. Hydro energy, because of the water "fuel", is an even more economical energy.

4.2.2 Outlook for Existing Demand-Side Resources

Demand-side resources are typically much more difficult to quantify because they are much smaller than supply-side resources and are dispersed amongst thousands of customers with ever-changing attitudes. On the other hand, a supply-side generating plant can be totally utility-controlled with basically constant performance capability year after year. Nonetheless, demand-side resources exist today and will continue to be an important part of Nebraska resources in the years to come.

The impact of demand-side resources tends to get blended in with the utility load forecasts as mentioned in Subsection 4.1.2, especially once they are in place or are committed for implementation. Examples of such existing and committed resources and their outlook are given in Table 4.2.2-1.

FIGURE 4.2.1-1
1991 CAPACITY MAKEUP OF NEBRASKA SUPPLY-SIDE RESOURCES BY FUEL TYPE

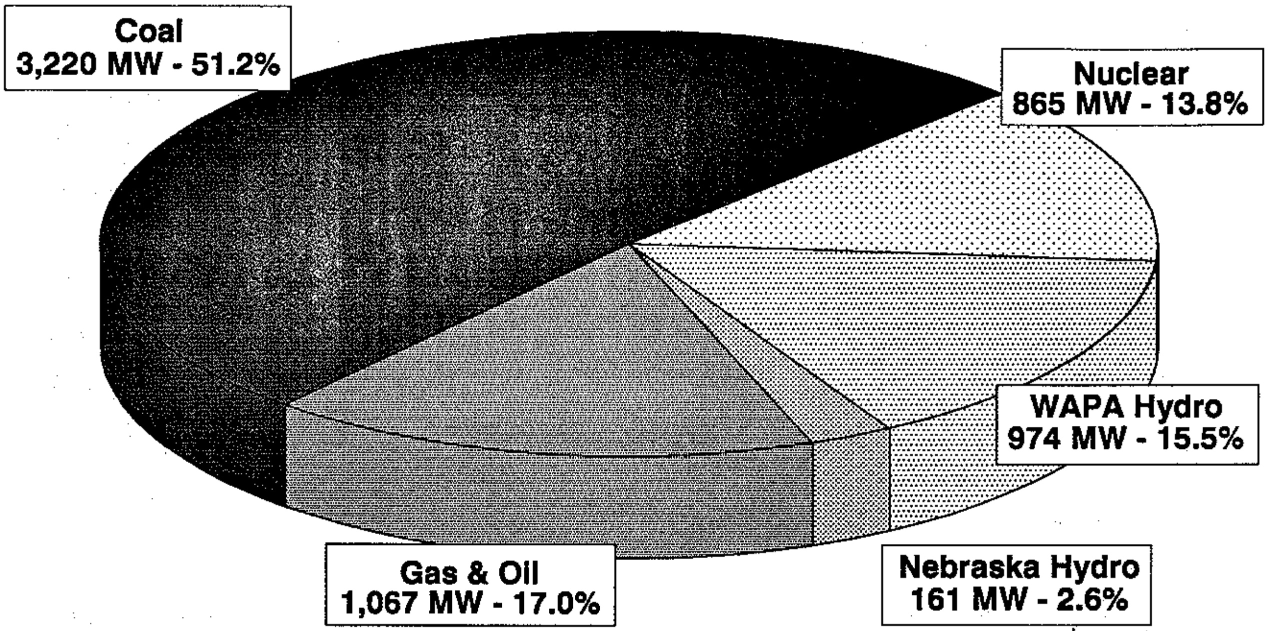


FIGURE 4.2.1-2
1991 ENERGY MAKEUP OF NEBRASKA ELECTRICITY NEEDS BY FUEL TYPE

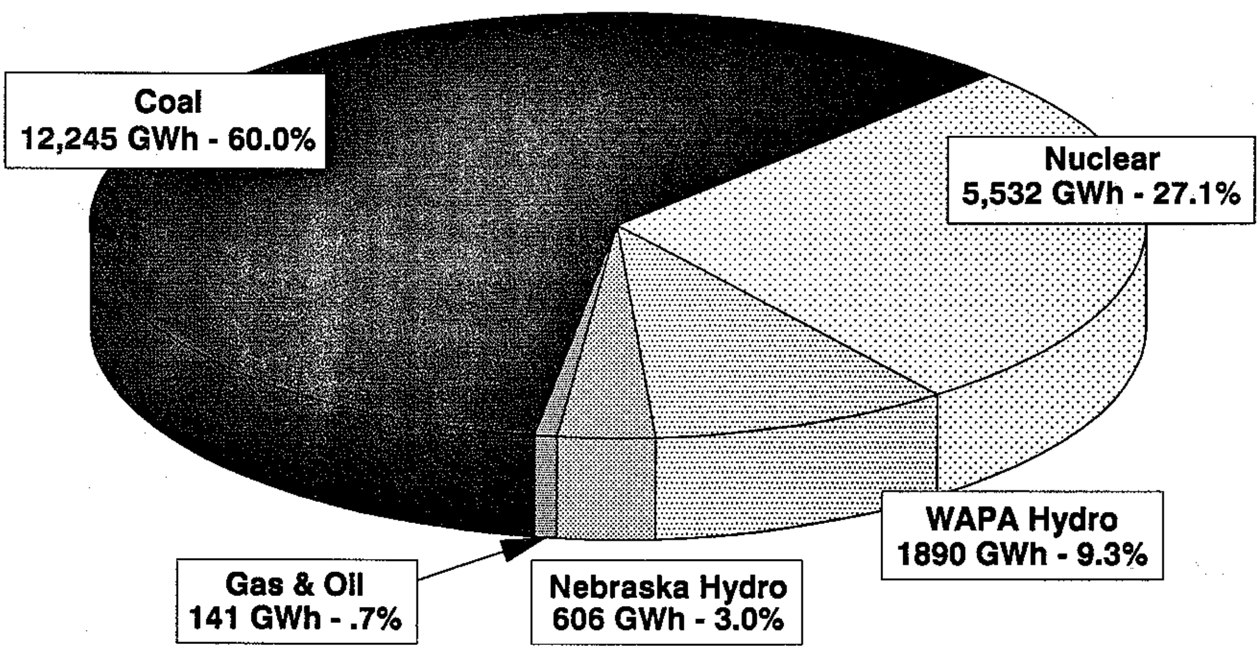


TABLE 4.2.2-1 Existing Demand-Side Resource Outlook	
PROGRAM DESCRIPTION	**EXPECTED OUTLOOK**
Irrigation Load Management	Currently reduces summer peak approximately 230 MW. Reduction is expected to grow to approximately 430 MW by year 2010.
Conservation in Irrigation - low pressure operations - efficient (lesser) water application	Already widespread and expect continued and somewhat improved activity in this area.
Air Conditioner and Water Heater Load Management	Small amount in place today, some expansion probable in this area.
Industrial/Municipal Bulk Interruptible Loads	Small amounts today, some expansion probable.
Conservation in Residential, Commercial, Industrial - insulation and weatherization - efficient appliances, motors - efficient lighting - price-induced changes in usage	Considerable activity today and expect continued educational and promotional programs as well as continued governmental rulemaking, especially on appliance efficiencies. Many of these rules are in effect now or will be by 1992.
Time-of-Use Rates	Minor amounts in use but continued, likely increasing use expected.
Controlled Voltage Reductions at Peak	Some existing use and continued, expanding use expected.
Load Building for Improved Load Factor---Space Heating and Water Heating	Significant incentives being offered, expect some to continue in some form.
Conservation in Streetlighting	Significant amount existing and expect continued, expanding reliance on more efficient fixtures.

A quite detailed listing of existing utility-specific demand-side programs is presented in the report on a statewide survey of "Electric Utility Activities in Energy Conservation, Load Management, Renewable Energy Sources, Research & Development, and Cogeneration/Small Power Production" submitted to the Nebraska Power Review Board by the NPA in 1989 with an update scheduled for 1991.

In summary, the demand-side activity of the utilities in Nebraska are many and varied and are expected to intensify in the future. The ability to evaluate the cost and quantify the impact (availability) of these demand-side activities should improve as the involvement increases, but probably will always be more difficult than such analysis on the supply side.

4.2.3 Outlook for Fuel Costs (Existing and Future Units)

As noted in Section 4.2.2, the four primary fuels utilized within the state (excluding hydro) are uranium, coal, natural gas and oil. In determining existing and future unit fuel costs for coal, natural gas and oil, the Integrated Planning Task Force formed a consensus based on 1989 actual price levels and escalation rates based on each utilities' projection of the market. Coal contracts are assumed to be renegotiated at market prices upon their expiration.

Future coal costs are seen as being dependent upon the size of the future unit (tons of coal per year) and on the transportation costs associated with it. The first new coal unit is anticipated to be a second unit at Nebraska City. The second and third new coal units will likely be located on new sites elsewhere in the state, or possibly, small expansion units at existing sites. Based on the above and taking into consideration the differences in assumptions concerning the future cost of coal between the utilities, it was decided to use the pricing basis shown in Table 4.2.3-1.

TABLE 4.2.3-1
1990 Fuel Cost Basis for Future Projections

Coal Unit	$/MMBtu
OPPD, Nebraska City/N. Omaha	0.75
NPPD, Gerald Gentleman	0.70
LES, Laramie River	0.65
Future Coal (Statewide)	0.75

Natural gas and oil prices for both existing and future units were determined again by consensus. While oil prices appear relatively uniform statewide, natural gas appears to be slightly more expensive in the eastern end of the state. A statewide pricing for natural gas has been developed. Table 4.2.3-2 indicates the 1990 fuel pricing basis to be used.

Nominal fuel cost escalation rates are indicated in Table 4.2.3-2 as well. Natural gas and oil price forecasts will increase to about 2.0% per year real in the long term with coal at essentially a zero rate of real escalation based on an inflation rate of five percent.

TABLE 4.2.3-2
Summary of Fuel Cost Projections

	Future Coal	Natural Gas	Oil
1990 Fuel Price	$0.75/MMBtu	$2.31/MMBtu	$4.095/MMBtu
1990 Escalation Rate	5.0%	5.0%	5.0%
1991 Escalation Rate	5.0%	5.0%	5.0%
1992 Escalation Rate	5.0%	6.0%	6.0%
1993-2010 Escalation Rate	5.0%	7.0%	7.0%
General Inflation Rate (Statewide) 5.0%			

4.3 General Economic Assumptions

Economy of operation is certainly a major consideration for utilities in satisfying their customers' strong desire for low rates while, at the same time, making prudent reliability, environmental and customer service decisions. For the economic aspects of the Study, several general economic assumptions apply as listed in Table 4.3-1.

TABLE 4.3-1 General Economic Assumptions for the Base Case	
PARAMETER	**VALUE**
General Inflation	5% per year
Nominal Interest Rate (municipal bonds)	8% per year
Discount Rate Nominal Real	 8% per year 2.857% per year
System Equivalent Debt Coverage Requirement	1.0

4.4 Transmission Assumptions and Analysis

Growth in electric power demand necessitates not only the addition of power generation resources, but also enhancements to the power transmission system which transports power from its generation sources to the load centers. Customer growth will also cause changes in the local transmission systems required to serve the load. The transmission network consists primarily of transmission lines and substations at various high and extra-high voltage levels (see the transmission map in Appendix E). It is designed to include some reserve capability, i.e., it can still operate reliably for a variety of facility outage conditions.

Therefore, in order to accurately assign costs to various supply-side alternatives, associated transmission facility additions required for each alternative must be included. These required transmission additions vary for the different supply-side options, depending on a unit's MW size and on its site location. The location of a plant site is determined by a variety of factors, among which are: proximity to, and transportability of, the unit's fuel supply; availability of cooling water; environmental impacts, particularly emissions into the air; distance from the load centers; etc. The further a plant site is relative to the location of the load centers, the greater will be the cost of the necessary transmission enhancements. The smaller a single unit is, the more distributed the siting can generally be, and also the units can generally be built closer to the load centers. Both of these factors will tend to reduce the cost of the related transmission additions.

For any supply-side alternative, the total cost consists predominantly of the basic resource cost (90% or more). The associated transmission cost is a relatively small proportion (10% or less). So the impact of the transmission costs is not great, but such costs are still recognized. In this Study, transmission costs were included, but not in an extremely rigorous fashion. In other words, the Study did not include detailed site comparison analyses. Rather, consideration was given to alternate sites only for the larger baseload options which were being selected in the optimization computer runs, and for these cases the costs for different sites were averaged, and the average cost was included. Other system transmission additions which were not associated with specific resource alternatives were included as part of the total revenue requirement although not split out to specific resources.

Two alternate sites for large baseload units (either 600 MW units burning Powder River Basin coal, or 500 MW IGCC units) have been identified in the past and were previously considered in the transmission portion of the 1986 NPA Statewide Resource and Transmission Planning Study. One is a site near Lincoln, and the other a site in central Nebraska (generally in the Blaine/Custer County area). These were again considered to be the primary new sites for such units in the state. From transmission expansion plans determined in 1986 for the Lincoln and central Nebraska sites, revised transmission cost estimates were prepared. An estimate was prepared for a first unit and for an expansion (second) unit at each location. The average of the two first unit estimates, and the average of the two expansion unit estimates, are used in the 1991 Study.

It is also assumed, without detailed evaluation, that at least three existing plant sites could be expanded by adding a 250 MW baseload coal unit from such site opportunities as Hastings, Grand Island, Gerald Gentleman, and North Omaha. The representative scenario of adding 250 MW units at both Hastings and Grand Island (500 MW total), was used for specifying the cost estimates for required transmission facility additions. This average cost was used for each of the three 250 MW units considered in the Study.

Table 4.4-1 lists the overnight construction cost estimates for transmission facilities included in this Study for the various supply-side alternatives. These costs are included in the total alternative construction cost given in Table 4.7.1-1.

TABLE 4.4-1
Overnight[1] Construction Costs Assumed for the Transmission Facilities

Unit Type	Nebr. City #2	New Coal	New Coal	C.T.	Comb. Cycle	Fuel Cell	IGCC	CAES	Adv. Battery
Max. Capacity (MW)	600	600	250	80	150	8.9	500	110	20
Initial Unit at a Site (1990$/KW)	N/A	123	N/A	10	40	3	123	40	3
Expansion (2nd) Unit (1990$/KW) at a Site	78	98	92	10	40	3	98	40	3

[1] Does not include interest during construction cost.

It should be noted that the transmission facility additions which have been addressed above in this section are those specifically associated with (i.e., required by) the various supply-side resource alternatives. The expansion of certain other transmission facilities more generally required to carry power to, and throughout the areas of, the load centers was not identified in this Study. Transmission expansion for load areas will be necessary for all types of resources. Such facilities are generally more localized and require less mileage; therefore they have a less significant cost impact.

4.5 Environmental Assumptions

The environmental impacts of generation resources are receiving more and more attention within the utility industry and the country in general. The same is true in the transportation industry. For example, the passage of the Clean Air Act Amendments of 1990 established limits on the amount of sulfur dioxide (SO_2) and will establish limits on the rates of nitrogen oxides (NO_x) emissions. This Study includes some allowance for uncertain future environmental costs.

This section describes the primary environmental impacts of power plants and transmission lines, methods of control, summarizes the law, and shows the environmental performance of Nebraska utilities.

4.5.1 Primary Environmental Impacts

Among today's many environmental impacts, acid rain, the greenhouse effect (global warming), and depletion of the ozone layer are the most prominent concerns. Actually there is still debate on cause and effect and to what degree electric utility operations contribute to each of these phenomena. The principal air pollutants produced by fossil-fueled power plants are sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), and particulates (ash and dust). Normally 98-99 percent of particulates are removed by electrostatic precipitators or baghouses in coal-fired power plants. Particulate emissions are generally negligible for other fossil-fueled power plants (i.e., gas and oil). None of these pollutants have been shown to be significant in the depletion of the upper atmospheric ozone layer.

All known costs of environmental control, including waste disposal, are factored into the Study as described further in Section 4.6.2.

CO_2 is emitted when fossil fuels are burned and when SO_2 is reacted in a scrubber. It may contribute to the greenhouse effect. NO_x emissions may also contribute to the greenhouse effect and also react with other airborne chemicals to produce low altitude ozone and smog. NO_x, and especially SO_2, appear to contribute to acid deposition. SO_2 has also been implicated in some visibility concerns and may alter cloud reflectivity which actually could then counter effects of greenhouse gases.

There are, however, other environmental issues facing electric utilities in addition to the air quality issues addressed. Some of them are:

Waste Disposal (Nuclear & Non-nuclear)	Thermal Discharges
Land Use	Vapor Plumes
Water Use	Increased Rail Traffic
Visual Effects	Noise Levels
Electric & Magnetic Field Effects	Methane Releases at Coal Mines
Transmission Line Effects on Migrating Water Fowl	Endangered Species

These issues were not totally quantified except to the extent they are included in the cost to construct and operate a facility. For example, water reuse facilities and cooling towers are assumed in all new coal plants in this Study. Any impacts beyond the utility's cost for the items above are very difficult to quantify and have been considered as environmental externalities, as described in Section 4.6.3.

4.5.2 Methods of Environmental Control

In order to control SO_2 emissions, several methods can be employed. The type of fuel burned affects the amount of emissions. Units burning natural gas emit very little SO_2 and less NO_x than units burning coal. It should be noted that the coal burned in the power plants in this area is usually a subbituminous coal from the Powder River Basin in Wyoming and has a low sulfur content compared to coal found in other parts of the country. In fact, an option for some other utilities to reduce SO_2 emissions would be to change the fuel they use to the low sulfur coal that Nebraska utilities use.

In addition to fuel choice, SO_2 can be controlled by physically removing it from the exhaust gases emitted from the unit. This is done in conventional coal units by special equipment called scrubbers. The efficiency of scrubber technology in removing SO_2 is continually being improved. Some developing technologies may further improve the efficiency of scrubbers.

Other methods of burning coal are also being developed for reducing SO_2 emissions. One is a fluidized bed technology where the SO_2 is largely removed as part of the burning process and is not exhausted to the atmosphere. Fluidized bed technology is available in smaller units and is being tested in utility size units.

The control of NO_x emissions can be facilitated by changes in fuel mix, burner design, water or steam injection, and selective catalytic reduction. Emissions of CO_2 are more difficult to control. There is some research being done on control technologies but nothing is commercially available at this time. A way of partially offsetting the CO_2 emitted is to plant trees that utilize CO_2 as they grow.

Converting from coal to nuclear or installing renewable resources are ways of reducing SO_2, NO_x and CO_2 emissions. Gasifying coal reduces the utilities' point-source emissions of SO_2 and NO_x. In addition to these methods of improving the emission characteristics of supply-side resources, demand-side resources that cause lower load for a given service would result in lower fuel consumption and possibly lower emissions, depending on their specific effect on the generation mix.

4.5.3 Environmental Law

The most recent Clean Air Act Amendments were passed in 1990 but regulations to implement the law are not scheduled to be completed until 1992. These Amendments primarily relate to emissions of SO_2, NO_x, and air toxics. There has also been legislation proposed that would create taxes on carbon fuels. The final outcome of these laws will have an effect on costs and perhaps future plans. In the sensitivity studies, a case was run to determine the high cost effects of HR 4805, potential carbon tax legislation.

4.5.3.1 Existing Environmental Law

There are many environmental regulations that have to be met before supply-side facilities can be installed and operated. Some of the pertinent regulations and legislation along with their effects are tabulated in Table 4.5.3.1-1. Besides complying with these environmental laws, the utilities are subject to other regulating bodies such as the Nebraska Power Review Board, the Nebraska Public Service Commission, and the Federal Aviation Administration.

The Clean Air Act Amendments of 1990, signed November 15, 1990, add environmental requirements beyond those listed in Table 4.5.3.1-1. With the passage of these Amendments, owners and operators of electric utility generating units will be subject to a significant number of new regulations affecting allowable air emissions of SO_2 and NO_x as well as the overall operation of their facilities.

Title II of the Clean Air Act Amendments of 1990 also addresses motor vehicles and establishes tailpipe emission standards for cars and trucks with target dates of 1994 and 1998. It establishes that fleet vehicles should be cleaner than personal use vehicles. Title III of the Act addresses air toxic provisions and establishes that the EPA will do a study on emissions of 189 named toxic substances and publish regulations if any substance is found to be detrimental to public health. In addition, the EPA will do a separate study of mercury emissions from power plants.

Title IV contains the Acid Rain Provisions and is the primary section of the law relating to electric utilities. The specific purposes are to reduce overall annual SO_2 emissions to 8.9 million tons by 2000 and to reduce NO_x emissions by 2 million tons per year. It establishes base line unit emissions, and creates marketable SO_2 allowances. Title V establishes the

TABLE 4.5.3.1-1
Existing Environmental Law for Preconstruction Licensing
(adapted from Gibbs and Hill, 1979)

Law, Permit or Action	Effects
The National Environment Policy Act of 1969 (NEPA)	"Major Federal actions" require submitting Environmental Impact Statement (EIS). Thus if Federal permits are required an EIS would also be required.
The 1972 Federal Water Pollution Control Act and Amendments 1977	May not have to comply with zero discharge waste water system, but will have to apply for waiver of National Pollutant Discharge Elimination System (NPDES) requirements. U.S. Army Corps of Engineers Permit required for use or crossing of water ways.
The Clean Air Act 1970 and the 1977 Amendments	Provisions to Prevent Significant Deterioration (PSD). New sources are required to use Best Available Control Technology (BACT). New Source Performance Standards (NSPS) establish minimum acceptable emission control requirements for BACT. Set up National Ambient Air Quality Standards (NAAQS). PSD provisions require ambient air quality and meteorological data collection to support permit application. Standard for NO_X set up. Standards for Total Suspended Particulates (TSP), limits use of tall stacks for pollution control, establishes policy of protecting and restoring visibility in Class I areas. Implementation plans approved by EPA Air Quality Permit required from State.
Resource Conservation and Recovery Act (RCRA) of 1976	Solid waste disposal from facilities including waste from air pollution control facility. Solid waste disposal permit required from state.

TABLE 4.5.3.1-1
Existing Environmental Law for Preconstruction Licensing

Law, Permit or Action	Effects
The Noise Control Act of 1972	Sets Noise Standards usually addressed in EIS. Preconstruction baseline needed.
Occupational Safety and Health Act (OSHA) Noise Standard*	Standards enforced by inspection.
Toxic Substances Control Act of 1976	Supplements parts of Clean Air Act of 1970 and Federal Water Pollution Control Act 1972. Standards for regulation of PCB's. Provides for testing by EPA.
Other State Permits as required (other local permits may be required also)	Waste water treatment permit. Construction waste disposal permit. Permit to develop disposal wells. Department of Water Resources permit for construction in a flood plain - permit for makeup water wells - permit for potable water wells - permits for water usage Department of Health registration of potable wells. Department of Health radioactive material license.

*Some Nebraska utilities are not subject to OSHA standards.

permit provisions, Title VI addresses stratospheric ozone protection, Title VII concerns federal enforcement, Title VIII has some miscellaneous provisions including carbon dioxide data collection provisions, Title IX addresses clean air research, Title X addresses disadvantaged business concerns, and Title XI addresses job displacement provisions.

Although the law is in place, the regulations are not. By May 15, 1992, the EPA is to have the major regulations in place. The Act does establish various dates for utility elections under the law. The first elections were due on March 31, 1991 and additional filings will be due prior to the issuance of final regulations.

The implementation of Title IV of the Act is split into two parts, Phase 1 generating units and Phase 2 generating units. Phase 1 units, with emission limits to be achieved by 1995, are the units with higher emission rates (SO_2 emissions greater than 2.50 lbs/MMBtu). The 1995 targets are not as stringent as the later goals. None of the units in Nebraska are Phase 1 units. All Nebraska fossil units, which are Phase 2 units, become "affected units" in 2000, when the Act has direct application to Nebraska.

Beginning in 2000 the utilities in the state will have to keep their SO_2 emissions below the targeted amounts based on actual emissions during 1985 through 1987. These targeted amounts, or allowances, when added up for a system are the total SO_2 emissions allowed by that utility on an annual basis. If in a given year a utility produces less SO_2 than it has allowances, the left-over allowances can be "banked" for use in the next year or years thereafter or they can be traded or sold. When a utility produces more SO_2 than its allowances for a year, they can draw from their bank. If they do not have a bank they will have to buy allowances from some other utility or at auctions in order to meet the target allowances or pay a significant penalty. Such penalty includes a financial payment plus a reduction in the following year's allowance by the amount of the overrun. It is envisioned that there will be trading, selling, or leasing of allowances and these transactions will most likely affect Nebraska in the Phase 2 period. The actual trading structure has not been established as to who will administer it or how it will work. This will be developed as part of the regulations.

Since one goal of the Act is to put a "cap" on SO_2 emissions, the allowances described above are the maximum obtainable even in future years. Thus if a new generating unit is put into a system that is operating at its limit, the allowances to operate that new unit will be established by reducing the SO_2 emissions from existing units in some manner or purchasing allowances elsewhere. It should be noted that the intent of the law is to get existing units down to an emission rate of no more than 1.2 lbs/MMBtu and stay within the overall "cap". All the units within the state of Nebraska, or that are operated for use by Nebraska utilities, are well below this emission rate today. For Nebraska coal units with the highest SO_2 emission rates are in the range of 0.8-1.0 lbs/MMBtu and Laramie River Station Unit #1, with a scrubber installed, is the lowest at 0.14 lbs/MMBtu.

There are many other provisions of the law which need to be further defined by the regulations. There are several different means of complying with the law. Some of these include clean coal technologies and conservation and renewable options. The Act creates a credit for conservation and renewable options used, but the exact mechanism still needs to be defined.

4.5.3.2 Potential Environmental Legislation

During the last several federal legislative periods, the subject of CO_2 taxes has come up in several different ways. Carbon dioxide emissions are reported to contribute to the greenhouse effect. Thus taxes are viewed by some as a means of ultimately reducing the CO_2 emissions, or paying damages. Some of the taxes that have been proposed are very high in relationship to coal costs for Nebraska. A \$15/ton tax on coal is proposed in one bill, House of Representative 4805, and is used as a high carbon tax in the sensitivity cases performed (see Section 4.7.2). This \$15/ton tax on coal is equivalent to a cost of \$0.90/MMBtu, a cost currently higher than the projected cost of coal for a new unit. In this Study the cost of coal, including the mining, the transportation, and all other costs to deliver the coal to the plant, is assumed to be \$0.75/MMBtu. Thus this level of tax would more than double the cost of fuel for the coal-fired plants in Nebraska.

4.5.4 Environmental Regulators

Many of the environmental regulators are identified on Table 4.5.3.1-1. In addition, there is also the Nuclear Regulatory Commission (NRC) which directs the environmental and safety regulations of the nuclear facilities in the state.

4.5.5 Environmental Performance of Nebraska Utilities

As briefly discussed in Section 4.5.3.1, power plants of Nebraska utilities have emission rates substantially below the national average and even the targeted goals of the Clean Air Act Amendments of 1990. Table 4.5.5-1 lists the existing fossil-fueled units within the state of Nebraska greater than 70 MW and presents their emission rates in comparison to the current regulation targets.

Future coal units are anticipated to have 90-95% efficient scrubbers and burn low sulfur coal. As such, SO_2 emissions from a new unit are estimated to be 0.085 lb/MMBtu which is below the Laramie River Station emission level reported in Table 4.5.5-1. The NO_x emission rate for new coal units is estimated at 0.3 lb/MMBtu.

Figures 4.5.5-1 and 4.5.5-2 show the emission levels for SO_2 and NO_x respectively by state. It is easy to see that Nebraska is one of the cleanest states in the country. Part of this is due to low population density, part is due to the low emission rates at existing coal units, and part is due to lower amounts of industrial facilities in the state. It can also be seen that the states along and east of the Mississippi River contribute significantly to the SO_2 and NO_x emissions of the country as a whole.

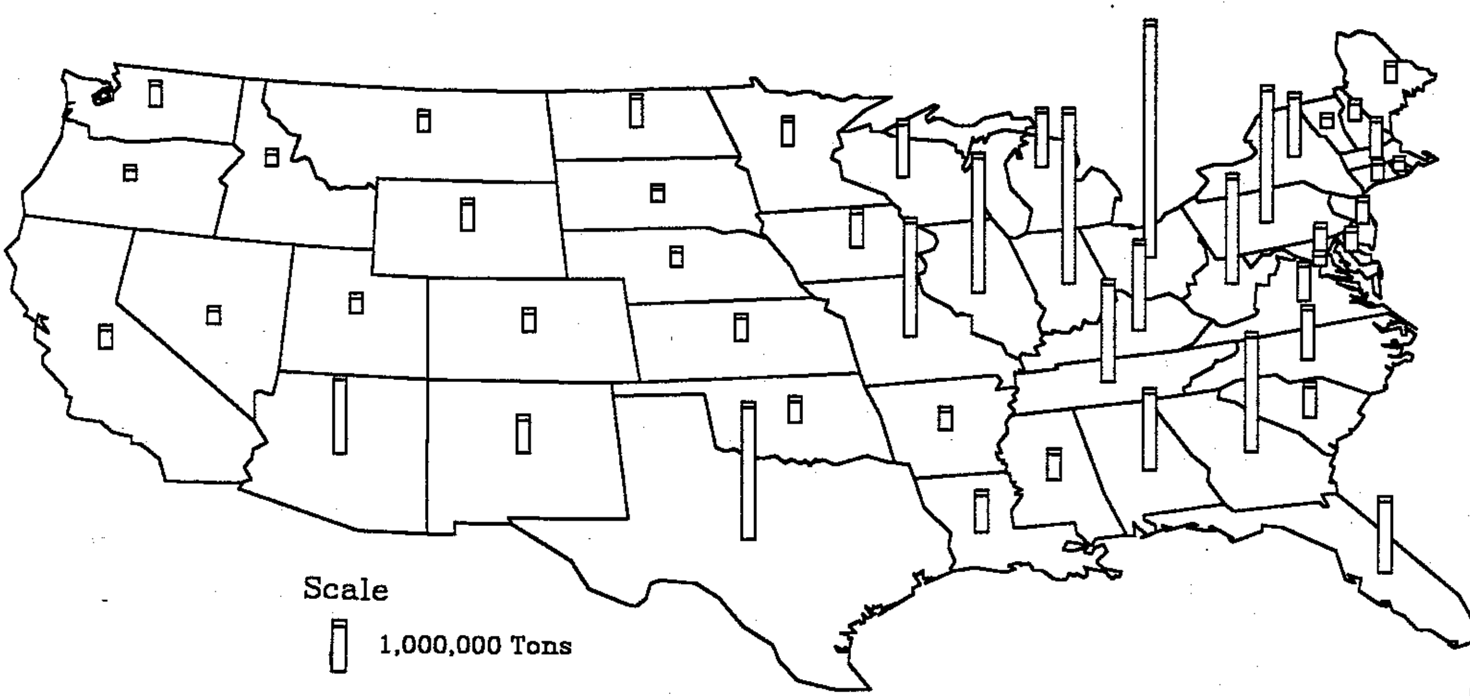
TABLE 4.5.5-1
Emission Rates for Electric Power Plants Serving Nebraska Load (>70 MW)

				Emission Rate (lbs/MMBtu)					
				SO_2		NO_x		Particulates	
Owner-Operator/ Companies Served	Plant Name (No. Units)	Fuel	Capacity (MW)	(a) Reg.	(b) Act.	(a) Reg.	(b) Act.	(a) Reg.	(b) Actual
OPPD/OPPD	N. Omaha/(5) Neb City/(1)	Coal/Gas Coal	630 585	2.50 1.20	.84 .84	NL .70	.70 .49	.10 .10	.06 .03-.06
NPPD/NPPD, LES	Sheldon/(2) GGS/(2)	Coal/Gas Coal	225 1278	2.50 1.20	.80 .70	NL .70	.73 .40	.17 .10	.071 .070
Gr.Island/Gr.Is.	Platte/(1)	Coal	100	1.20	.76	.70	.40	.10	>.10(c)
Hastings/Hastgs, MEAN	Egy Cntr/(1)	Coal	72	1.20	.80	.70	.40	.10	.015
Central/NPPD	Canaday/(1)	Gas/Oil	107	2.50	.016/1.0	N/A	.25/.31	N/A	N/A
Fremont/Fremont	Fremont/(1)	Coal	87	1.20	.94	.70	N/A	.10	N/A
Miss. Basin Pwr Prj./LES, MEAN, Tri-State	Laramie River Station (1)	Coal	550	.20(d)	.14	.70	.43	.10	.012

(a) Regulatory Limit
(b) Typical plant emission rate
(c) Based on opacity measurements
(d) Wyoming Standard
NL No regulatory limit
N/A Not Available

Figure 4.5.5 – 1

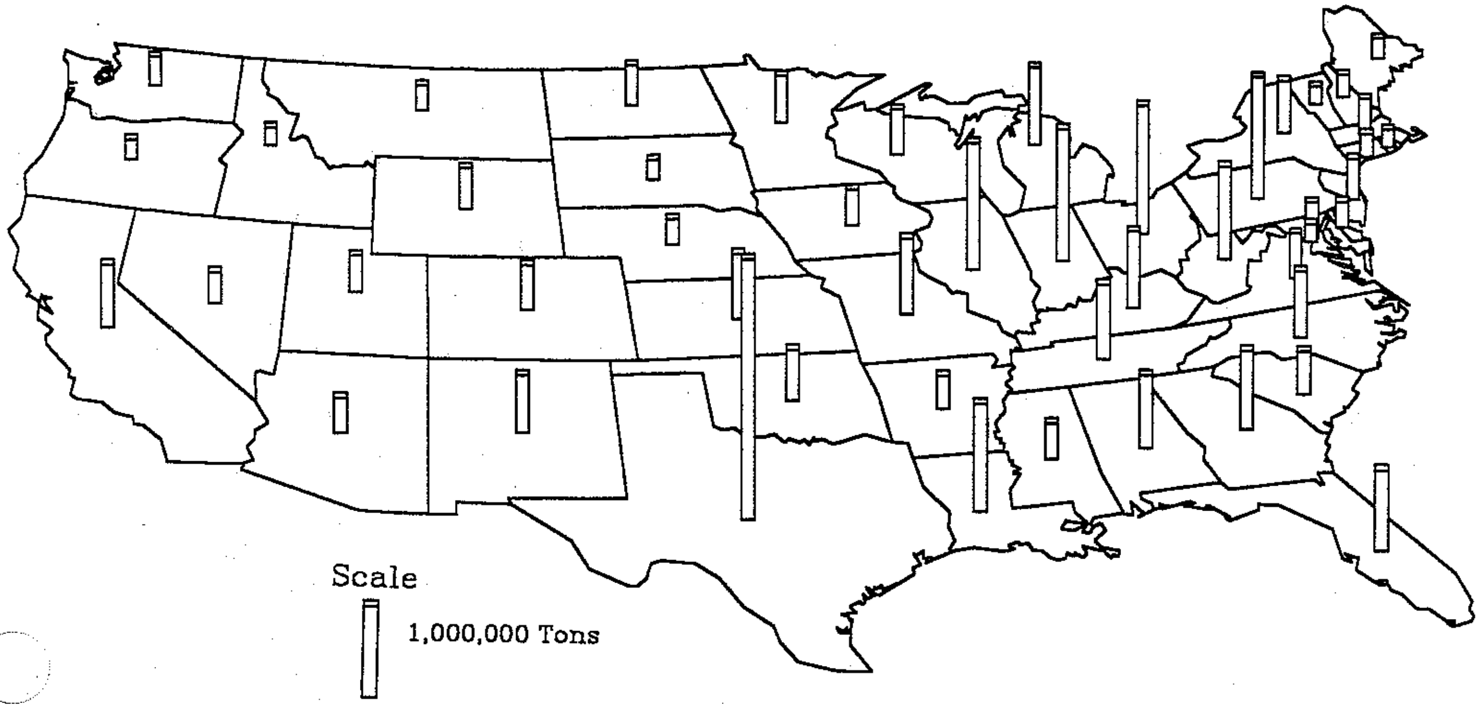
1985 Sulfur Dioxide Emissions



Source: National Air Data Branch, United States Environmental Protection Agency

Figure 4.5.5 – 2

1985 Nitrogen Oxides Emissions



Source: National Air Data Branch, United States Environmental Protection Agency

4.6 Evaluation Criteria

The purpose of a long-range resource planning study is to identify the best set of future resources. This best set of future resources will be dependent on the evaluation criteria that is used. The evaluation criteria is the measure by which one set of options can be compared to another. This criteria could be the net present value of electric system cost; the electric rates; the value of service provided; the present value of total cost including effects on those customers participating and those not participating in DSM programs plus electric utility and environmental costs; or various combinations of these possibilities. The clearest example as to how the criteria affects the results is on participant and nonparticipant cost. There may be a DSM program that is beneficial to the DSM participant. But that program increases the cost of the nonparticipant. Now there is a question as to whether that program is a good option or not.

Regardless of the primary criteria that is used, it is still possible to evaluate the effects on all parties in most studies. This may require some additional data gathering but is useful for at least identifying how all parties are impacted by decisions.

The evaluation criteria selected for this Study is to minimize the net present value of total cost (total cost test). This means that the total quantifiable cost (including primary environmental), when viewed from the combined perspective of the utility and its customers is minimized. It may not necessarily mean that the cost from each perspective is minimized. The rationale for using this test is that if the total cost of a set of options is lower than another set it is the preferred thing to do. Then, presumably, the benefits can be redistributed in some equitable manner.

The next two sections further identify the costs that are included in the Study. It is true that not every cost to society is included in this Study. That is, there are still some externalities. However, including the total cost of the utility plus the primary costs of the customer and the primary costs to the environment is, to a large degree, least cost planning.

4.6.1 Net Present Value of Costs Over the Study Period

As mentioned previously, the primary evaluation criteria is a total cost test for the study period as calculated in net present value terms. This means that the time value of money is taken into account in the analysis. It recognizes the fact that a dollar tomorrow is not worth as much as a dollar today and allows cases with significantly different cash flows to be compared to one another. Net present value is a standard economic analysis method. It is used by the federal government and by individuals and companies trying to decide, for example, whether it is better to buy a product or lease it.

The next section presents more detail regarding the total cost test and the net present value calculation of those costs.

4.6.2 Costs Included in the Evaluation

The types of costs needed for the evaluation are partially determined by the purpose of the study and partially by the criteria chosen. Utility, customer, and environmental costs are needed for this Study. Utility costs include the cost of existing and future alternative resources, both supply-side and demand-side. The generation, or supply-side alternatives, have the transmission costs included. The construction cost of future generation alternatives also includes environmental equipment costs necessary to meet all applicable standards for compliance. Other electric system costs not directly related to resources, such as distribution costs, are also added. The cost information is in sufficient detail that given the load forecast, the total electric system cost can be converted into an average statewide electricity rate at the retail level.

The inclusion of DSM resource alternatives requires significant amounts of cost and other data. Data is required for each DSM option regarding program administration and incentive costs, customer participation rates, risk factors, effectiveness and reliability of each DSM option, etc. Customer costs and load shape effects need to be estimated in order to evaluate the benefits to the customers. Customer costs or benefits may even include some nonelectrical costs or benefits.

An example such as the heat pump study case can be used to clarify these DSM costs. For a high efficiency heat pump installed in place of a standard efficiency air conditioner, there is an incremental (extra) equipment cost for the installation. The high efficiency heat pump will use less electric energy during hours of air conditioning than the standard efficiency air conditioner. It will use electric energy in the heating months whereas the air conditioner option may be coupled with a natural gas furnace. The change in load caused by the heat pump installation is simulated for the electric system and all the benefits for the electric system can be derived from that simulation. In addition to the electric effects on the system and the customer, the gas consumption for this customer goes down. So the electric costs will go up for the consumer, the gas costs will go down, while the installation cost may be higher. If all of these cost changes are represented then a valid comparison between the heat pump case and the base case can be drawn based on a total cost criteria.

It should be noted that demand-side options are very utility specific and, to some extent, the costs may be utility specific. Also, the customer benefit may vary depending on the utility's particular rate structure and power supply situation. Thus at the statewide level the costs and load effects that are represented for the demand-side options are developed in average form and each utility may have a different picture when viewed independently.

Another cost that has been included is environmental cost. All new fossil units are represented as equipped with state-of-the-art environmental control technology together with an allowance for uncertain future environmental costs.

Using these three major cost components:

Generation and Transmission

Demand-Side Management (customer and utility)

Environmental

and all the associated detail, a total cost for a case can be determined. This total cost is used to compare one case to another and to determine the best integrated resource plan (i.e., least cost plan).

In theory all generation options and all DSM options can be entered into a model and run. As a practical matter supply-side and DSM alternatives can be grouped by generation type or load change type and the lower cost alternatives in a group can be identified and saved without running an exhaustive model. This screening process is discussed in Section 4.7.1 for Supply-Side and 4.7.3 for DSM.

4.6.3 Externalities

The ideal situation is to include all costs and all benefits resulting from an alternative and then a detailed analysis would result in the best decision. The problem is that it is difficult to evaluate <u>all</u> costs and <u>all</u> benefits. Impacts that are not possible to quantify or require very subjective quantification are sometimes referred to as externalities. In this Study, significant environmental costs were included as part of the total cost as described in Section 4.6.2.

There are, however, other externalities besides just certain environmental costs. One is national energy independence. That is, what is the value of relying on abundant fuel sources in this country that are readily available.

Customer reliability, or the value of dependable electric service to the customer, may be an externality. Although resource outages are assigned a cost in the Study, the value of reliable electric service is different between classes of customers. The value to a commercial customer or an industrial customer would be significantly different than the cost to a residential customer. Thus the commercial or industrial customer may place a higher value on dependable electric service than actually indicated by the costs they are paying. This increased value of service over and above the utility cost of service is an externality not quantified.

For demand-side alternatives, there are also externalities. For the industrial interruptible program, no net manufacturing cost impact is included for the loss of production during the interruption. Also more efficient lighting may not have quite the quantity or quality of light output, which in some production facilities may be a key factor in order to maintain high productivity. These kinds of externality are treated somewhat by the participation rates that realistically exclude those customers from programs where such problems would make the DSM program infeasible. In any case, reductions in productivity are not included.

All the government regulations that may come in the future can not be represented either. They are usually unknown today and are difficult to predict very far into the future.

These externalities and the many other future uncertainties associated with resource planning are why planning is an ongoing process. The future resources that are needed when viewed today may look somewhat different when viewed a few years from now. The key point in long-range resource planning studies is identifying as clearly as possible the earliest commitments and how changes in assumptions, or effects of externalities, could change the early decisions.

4.7 Resource Alternatives

After the load forecast has been established, the existing resources and their future status has been determined, and the general economic assumptions established, then a list of future resource alternatives is developed. This is the first step identified back in Figure 3.1-1 showing the NPA study overview. Thus, it is obvious that even prior to the first step shown in the overview, significant effort has been put forth.

In evaluating future resource alternatives, up-to-date information is needed. This information comes from contacts with planning organizations, research organizations, consulting firms, and other utilities. These efforts go into preparing a list of resource alternatives.

Some alternatives are commercially available meaning that cost and operating characteristics are usually well established. Other technologies may be just coming forward and are referred to as emerging technologies. Also there are many alternatives that are still in the research phase. Thus a study done today may view a resource, such as fuel cells, as an emerging technology. However, in a study done several years from now it may be considered commercial. Similar classifications are possible for demand-side resources as well. Efficient equipment is being developed continually, but the availability of some of it is currently limited. Thus for now, a certain efficient appliance may be considered an emerging technology, but in a study performed a few years from now it may be considered commercial.

In developing a supply-side resource alternative list, various information sources were used. A primary source is the **EPRI Technical Assessment Guide (TAG)**. EPRI's primary purpose is doing electric power research. EPRI publishes hundreds of books each year on various aspects of their research. The TAG is a compilation of resource alternatives with cost and operating characteristics compiled using consistent assumptions. They have volumes for both supply-side and demand-side options. Not all of the assumptions in TAG are directly applicable to the Nebraska options. However, the resource list and description of that alternative apply universally.

The next sections describe how these comprehensive lists are reduced to lists applicable to Nebraska. Each step in the process requires more and more data development. This screening process was somewhat described in Chapter 3 and shown in Figure 3.1-1.

4.7.1 Screening of Supply-Side Alternatives

The first step in the screening process for supply-side alternatives is to come up with a list of reasonably feasible supply-side options. The options that were selected are listed in Table 4.7.1-1. The second column identifies whether the unit is a baseload unit or a peaking unit and the third column presents the construction cost, usually including associated transmission.

The operational mode identifies whether a unit would be operated on a fairly continual basis as a baseload resource, or in a more limited role as peaking. The unit may be operated in a peaking mode either by utility choice, such as with a combustion turbine, or in coincidence of the unit with the system peak, such as with the solar units. More detailed explanation of these units can be found in Appendix F.

Costs for these eighteen options were prepared and categorized into two types of costs, fixed and variable. Fixed costs are costs incurred whether the unit produces energy or not. Variable costs occur when energy is produced, a primary example being fuel. Some specific information on fuel cost forecasts is given in Section 4.2.3. In the screening process, fuel costs in 2005 are used, although converted to real 1990$. The real costs of some fuels change by year of the Study because they escalate at a rate above inflation. The year 2005 is selected because it is an important year in some of the major decisions. Generally, units that are preferred for operation as baseload are those with low variable costs of operation. Those units that are preferred for operation as peaking generally have low installation costs or low fixed costs.

These eighteen options represent a very broad spectrum of cost and operating characteristics. It is important to compare these resources against one another on a cost basis. One method of doing this is called a screening curve analysis. This is a simplified analysis where the levelized cost of the unit is calculated on a per unit (KW) basis at various capacity factors depending on fixed and variable costs. These costs are then plotted and one alternative can be compared to another. In order to limit the number of lines on a given

TABLE 4.7.1-1
Initial Supply-Side Alternatives List

Unit Types	**Operational Mode**	**Overnight Construction Cost[1] 1990$/KW**
Nebraska City No. 2	Baseload	1070-2nd
600 MW Coal	Baseload	1297-1st 1094-2nd
300 MW Coal	Baseload	1620-1st 1331-2nd
250 MW Expansion Unit Existing Site	Baseload	1262-2nd
Combustion Turbine	Peaking	350-1st 298-2nd
Combined Cycle	Peaking	582
Fuel Cells	Baseload	591
Integrated Gasification Combined Cycle	Baseload	1534
Compressed Air Energy Storage	Peaking	544
Advanced Battery	Peaking	668
Advanced Nuclear	Baseload	1549
Pumped Hydro Storage	Peaking	1100
Wood	Baseload	1618
Solar Photovoltaic	Peaking	2704
Solar Thermal Central Receiver	Peaking	2926
Atmospheric Fluidized Bed Coal	Baseload	1581
Wind	Peaking	1724
Municipal Solid Waste	Baseload	4736

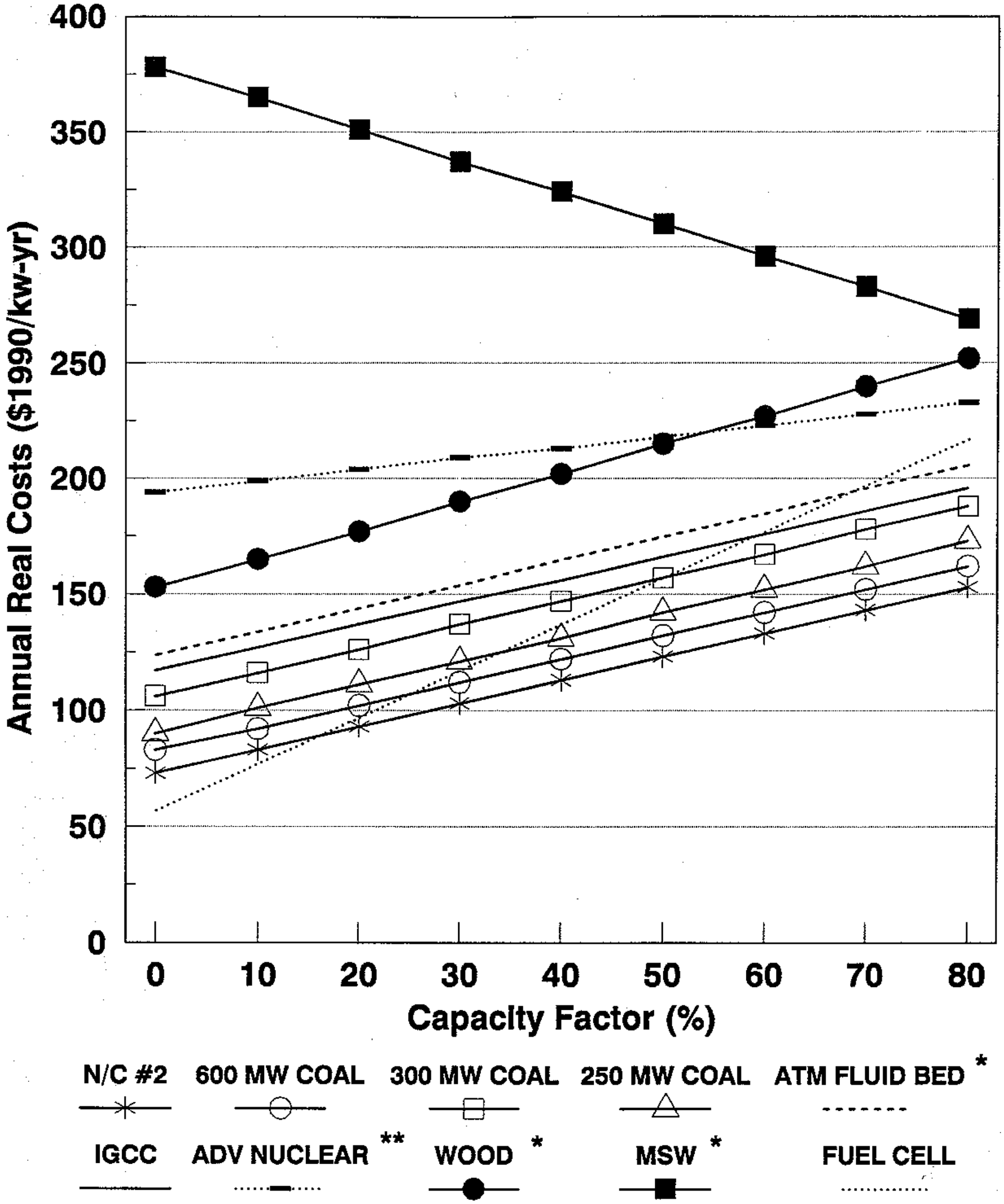
[1] Outlet transmission costs from Table 4.4-1 are included in all except advanced nuclear, wood, atmospheric fluidized bed, and municipal solid waste options. Interest during construction is not included.

chart, two charts are prepared, one for baseload alternatives and one for peaking alternatives. Transmission and environmental costs are included in the screening curves. The components of cost are shown in Section 5.1.2.

Figure 4.7.1-1 contains the screening curves for the baseload alternatives. At zero capacity factor, the figure represents the fixed cost to install and operate the unit. The baseload unit with the lowest cost at zero capacity factor is the fuel cell, and that with the highest cost is the municipal solid waste. The slope of the line, or how quickly the line rises, is determined by the variable cost. The fuel cell line is based on gas cost which is an expensive fuel and thus it has a much more rapid increase as more gas is consumed. The coal units are somewhat flatter, the advanced nuclear is flatter yet, and municipal solid waste has a declining variable cost. This decline means that the disposal aspects (tipping fees) of a municipal solid waste facility is subsidizing the electrical portion and the more refuse burned the lower the per unit operating costs.

These lines, or screening curves, show which units are most economical at various operating capacity factors. A 10 percent capacity factor means the unit produces energy equivalent to operating 10 percent of the year at full load. Baseload units are normally operated anywhere between 30 and 70 percent capacity factor depending on size, fuel cost, and other operating constraints. The curves show that several units are clearly not economical choices. Thus, four of the baseload units are dropped from further consideration; municipal solid waste, wood, nuclear, and atmospheric fluidized bed. The rest were kept for further study. It was felt that the Integrated Gasification Combined Cycle (IGCC) was a higher cost unit than most other coal alternatives but provides one of the cleanest technologies and thus it is kept for use in the Clean Coal case.

FIGURE 4.7.1-1
NPA Screening Curve Analysis
Baseload Alternatives



* Transmission and full environmental costs are not included for these costly types.

** Transmission costs not included.

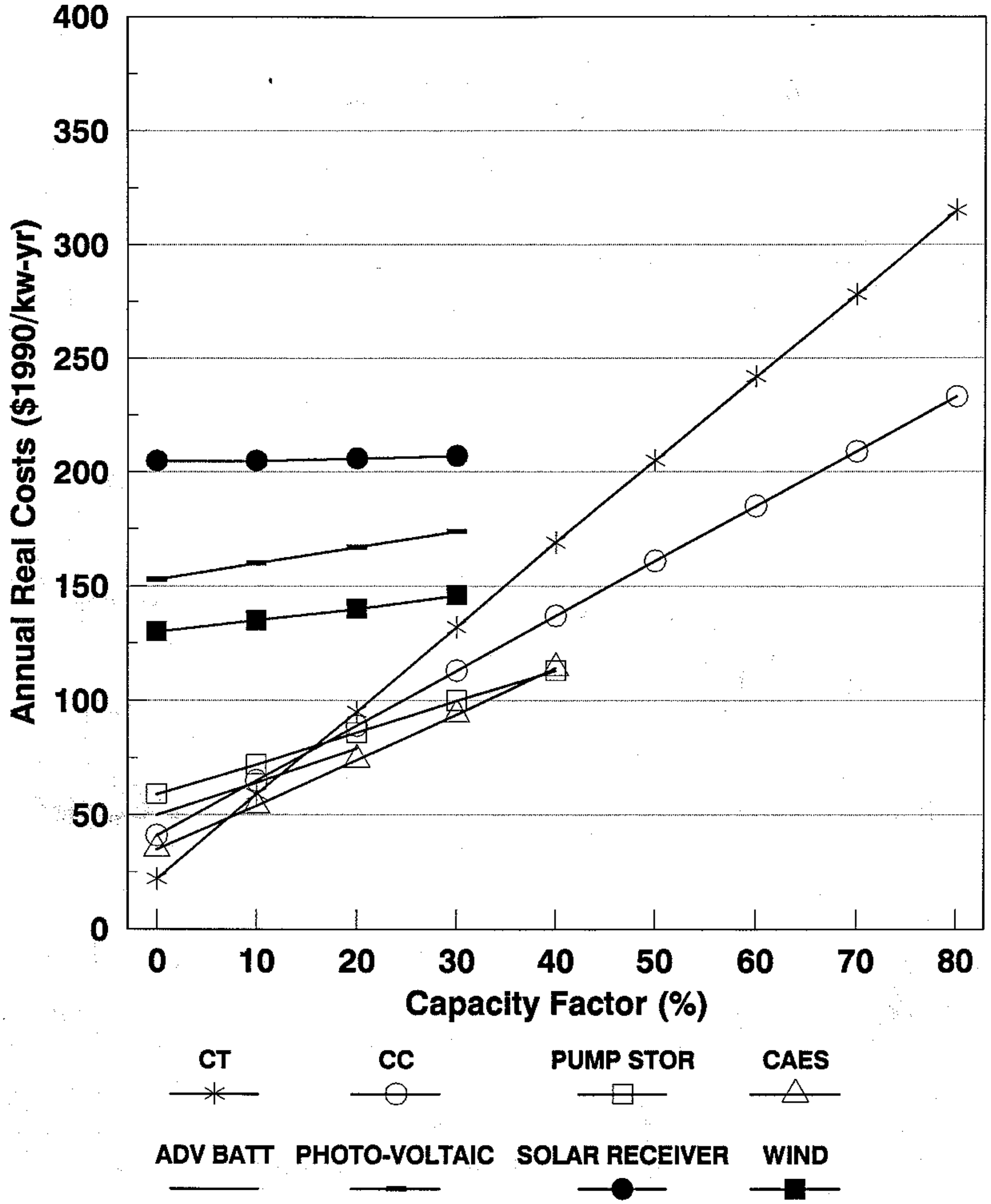
Similar data for peaking alternatives is shown in Figure 4.7.1-2. The resources that were dropped based on these curves are: hydro pumped storage, wind, solar photovoltaic and solar central receiver. None of these units has an economic advantage below a 30 percent capacity factor except for hydro pumped storage. In addition to the hydro pumped storage, however, both compressed air energy storage and batteries (other storage options) are less expensive under the 30 percent capacity factor. Thus these two units were retained and hydro pump storage was dropped. The remaining ten alternatives are six baseload (including IGCC for a special Clean Coal case) and four peaking types.

4.7.2 Optimizing the Supply-Side List with PROVIEW Runs

A list of nine options (excluding IGCC) still makes for a cumbersome calculation when demand-side management is included later. Thus a set of ten sensitivity cases are analyzed with PROVIEW to further limit these options. If a unit is not selected under any sensitivity case it is a likely candidate for removal from the final supply-side list. The ten sensitivity cases are listed below and are described further in Appendix G:

Base Case
HR 4805 Carbon Tax
Require Clean Coal Technology (IGCC case)
Higher Natural Gas Fuel Cost
Higher Coal Fuel Cost
Higher Combustion Turbine Capital Cost
Higher Coal Unit Capital Cost
High Load Growth
Low Load Growth
Raised Discount Rate

FIGURE 4.7.1-2
NPA Screening Curve Analysis
Peaking Alternatives



Based on the PROVIEW runs for these cases, the 300 MW coal unit and the fuel cell are eliminated, since they are never selected. For the peaking units, the advanced battery alternative is dropped because it is never selected and is higher cost than the compressed air alternative. This leaves four baseload alternatives:

Nebraska City No. 2
600 MW Coal (pulverized)
250 MW Second Coal Unit at Existing Site
Integrated Gasification Combined Cycle (for clean coal case)

The peaking alternatives are:

Combustion Turbine
Combined Cycle
Compressed Air Energy Storage

This is the list of resource alternatives that will be compared with the demand-side management alternatives. The list represents a set of units with varied cost and operating characteristics yielding a minimum cost for supply-side-only cases.

4.7.3 Selecting Representative Demand-Side Management Alternatives

EPRI defines Demand-Side Management as "The planning and implementation of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape . . . i.e., changes in the time pattern and magnitude of a utility's load."

Demand-side management can be done in many ways considering different customer classes, different end uses, and different penetration levels of the DSM option. Thus it is possible to develop hundreds of different options and literally thousands of different combinations of Demand-Side Management alternatives. In addition to the sheer number of possible DSM options, DSM usually has a small individual customer impact and has to be used by many customers in order to get a significant system load change. Further, data is less readily available for DSM options and a great deal of data is needed for detailed analysis as shown in Table 4.7.3-1. Also DSM is a very utility-specific resource alternative.

TABLE 4.7.3-1
Demand-Side Management Data Requirements for each Option

Initial Program Evaluation Requirements
Demand Impact/Customer
Energy Impact/Customer
Load Shape
Number of Customers (maximum)
Incremental Equipment Cost for Option vs. the Alternative
Incremental Operating Cost of Equipment
Other Costs or Benefits
Life of Equipment
Additional Data Required Before Implementation
Understanding of Customer Behavior
Likely Number of Participants at Incentive Levels
Individual Customer Benefit Based on Rate Structure

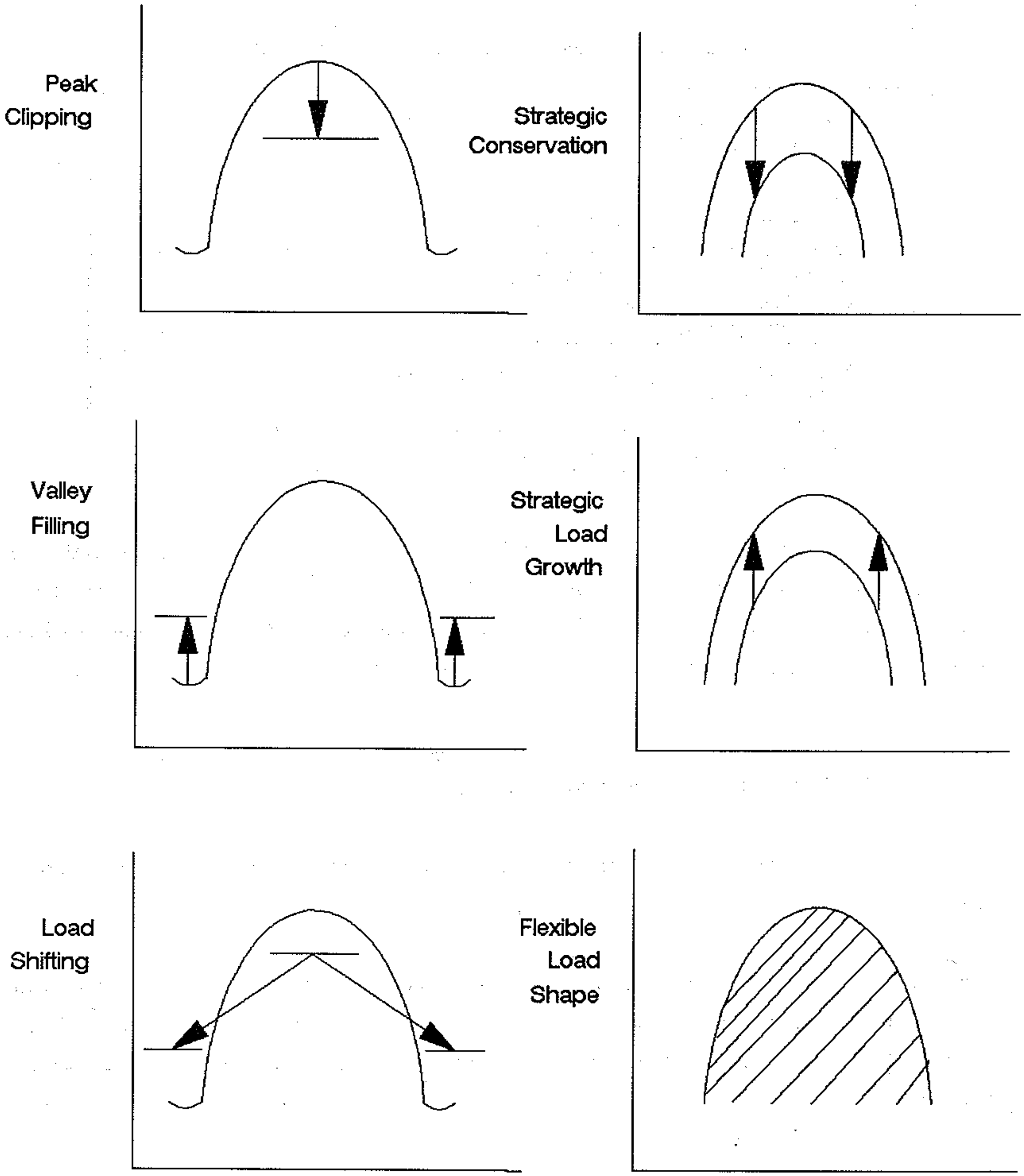
Previous sections have addressed supply-side alternatives in detail and have described the screening process to reduce those alternatives down to a representative number for use in the detailed modeling. For the reasons cited above, a similar process is needed to determine representative DSM alternatives.

4.7.3.1 EPRI Demand-Side Management Types

Figure 4.7.3.1-1 shows the six various DSM load shape objectives defined by EPRI.

Peak Clipping is a reduction in system peak which can occur by load management, interruptible load, or customer-owned generation. The peak loads for the day, or ideally the year, are reduced by this Demand-Side Management alternative.

FIGURE 4.7.3.1-1
EPRI LOADSHAPE OBJECTIVES



Valley Filling is an option where the peak demand remains the same but the off-peak loads are increased. These off-peak load increases could be on a daily cycle as represented in the chart or they could be loads in a normally low load period that are increased without affecting the peak for the year. Some such options are the addition of heating load for Nebraska utilities and the addition of a new load that uses the nighttime energy but nothing during the day such as battery charging for electric vehicles.

Load Shifting is a DSM option which reduces the peak and shifts the energy or perhaps more energy consumption to off-peak periods. The most common type of load shifting is cool storage technology, where air conditioner load during peak conditions is met by storage and the storage medium is recharged, or recooled, during the off-peak period.

Strategic Conservation is a load shape change resulting in a peak demand reduction and a reduction in loads throughout the period. Typical examples of this would be more efficient lighting, more efficient appliances, more efficient housing stock, i.e., generally the various kinds of conservation measures.

Strategic Load Growth is a load shape change that may increase demand and energy but is still economical. Although it is different from the depiction in Figure 4.7.3.1-1, strategic load growth could reduce the demand and energy in on-peak periods, and increase the energy in the off-peak periods. An example of this would be efficient heat pump installations in lieu of standard efficiency air conditioners thereby decreasing summer load and increasing winter load. This scenario is investigated in the Study.

Flexible Load Shape is a concept related to reliability where a customer may be able to pick the reliability he wishes. This is very utility-specific and is not used as an option in this Study.

For the first five load shape objectives, it was felt that at least one DSM option should be selected to represent that load shape objective. This constituted a key part of the DSM criteria for developing representative DSM Alternatives.

4.7.3.2 Representative DSM Alternatives

The first step in developing a set of representative DSM alternatives is to identify a complete list of the alternatives. Over 50 options were listed, many of which would be applicable to more than one class of customers. In reviewing this list to come up with representative alternatives, several criteria were considered:

Cost of the Option
Potential Effect on Demand
EPRI Load Shape Classification
Statewide Applicability
Commercial Availability

Many of the conservation options for residential customers were grouped into a conservation home concept. This conservation home included residential water conservation by flow restrictors and water heater blankets; high efficiency refrigeration; a high efficiency air conditioner or heat pump; and a high efficiency building envelope including additional attic insulation, low emissivity window films, new door/window caulking, and a new storm door.

The DSM options that were selected as representative and met the criteria above are:

DSM Option	EPRI Load Shape Objective
Air Conditioner "Scram"	Peak Clipping
Interruptible Load & Leased Generation	Peak Clipping
Electric Vehicle	Valley Filling
Commercial Cool Storage	Load Shifting
Commercial Lighting	Strategic Conservation
Conservation Home	Strategic Conservation
Efficient Heat Pump	Strategic Load Growth

The options selected give representative alternatives for each of the EPRI load shapes and appear to be applicable for the Nebraska utilities. Except for the electric vehicle, the options also have the potential of having significant demand effect on the system. They are all commercially available and would be available throughout the State.

Air Conditioner "Scram" is controlling air conditioners so that they do not run during the peak hour or hours. There would be a contracted amount of time that a customer's air conditioner could be shut off within a year in order to minimize the customer impact on an annual basis. This option is utility controlled in that the air conditioners are shut off from a local control center just as remote units are started from that center. The amount of control per customer is 3 kW and a <u>maximum</u> statewide capability would be 924 MW. This is the largest of the DSM options selected in terms of overall capability. Other distinguishing characteristics are identified in Table 4.7.3.2-1.

Commercial/Industrial Interruptible Load and Leased Generation is an option whereby a utility can operate a customer's standby generation in order to serve load during peak conditions, or the customer agrees to interrupt all or part of their load during peak load conditions for the utility. Since this program deals with much larger customers, not as many are required to yield the 217 MW total capability. The life of the standby generating units is similar to a generator installed by a utility.

Electric Vehicles offer the potential to increase utility loads at night during off-peak periods when the batteries would usually be charged. As passenger vehicles or business vans, they could each add annually from a few thousand to 15,000 kWh of load to the utility, nearly all off-peak. In addition, the cost of the fuel (electricity) per mile driven would be less than the gasoline for internal combustion vehicles and pollution emissions would be reduced, particularly in urban areas. The drawbacks are first that only vans are in commercial production, which limits the application. Secondly, the capital cost of the vehicles plus the cost of periodically replacing the batteries significantly exceeds current internal combustion

TABLE 4.7.3.2-1 Demand-Side Management Assumptions, End-Use Level						
	(1) AC Scram	**(2) Int Ld & Leas Gen**	**(3) Cool Storage**	**(4) Commerc Lighting**	**(5) Conserv Home**	**(6) Efficient Heat Pump**
Summer Demand Reduction (KW/Customer)	3.00	Not Avail	100.00	5.45	1.43	0.75
Energy Reduction (kWh/Customer)	Not Appl	Not Avail	(6,649)	26,278	1,773	387 Cooling (5479) Heating
EPRI Load Shape	Peak Clip	Peak Clip	Load Shift	Strategic Conserv	Strategic Conserv	Strategic Load Growth
Maximum No. of Customers	308,000	Not Avail	298	32,926	165,250	398,000
Maximum Demand Reduction (MW)	924	217	29	179	236	299
Incremental Equipment Cost ($/Customer)	$135	Not Avail	$20,000	$500	$1965	$800
Incremental O&M Cost($/Cust-yr)	$11	$0	$0	$0	$0	$0
Other Benefit ($/Customer-yr)	$0	$0	$0	$0	$0	Gas Savings $285
Life (years)	15	35	20	5	10-20	20

(1) AC Scram - Air conditioner load controls to shut off air conditioners during peak hours.
(2) Interruptible Load & Leased Generation - Commercial and industrial customers interruptible load and leased generation for use during peak hours.
(3) Cool Storage - Commercial cool storage to cool during peak hours and recharge in off-peak hours.
(4) Commercial Lighting - Commercial lighting replacing standard efficiency florescent lamps with high efficiency lamps.
(5) Conservation Home - Conservation home replacing standard efficiency refrigerator and air conditioner with high efficiency, plus better insulation and window coatings.
(6) Efficient Heat Pump - Replacing standard efficiency air conditioner with a high efficiency heat pump.

vehicle costs thereby impeding penetration of the market place. Further development will eventually bring lower costs and the need for further evaluation. For now, electric vehicles are not included as a demand-side option.

Commercial Cool Storage is an option whereby refrigeration equipment is operated during off-peak conditions to make ice or chilled water which is stored in insulated tanks and used during peak load conditions to meet all or part of a building's cooling requirements. This was the only load shift technology applicable for a summer peaking utility and thus it will be retained to this point even though the total capability is small at 29 MW.

Commercial Lighting is an option where more efficient lamps are installed in place of the standard efficiency equipment. Commercial lighting load is on during system peak and the heat from the lights contribute to air conditioning load as well. For the commercial customer, the most that efficient lighting may save is 5 kW and the additional air conditioner reduction would be another 1.7 kW. At the utility system peak, the total reduction is estimated at 5.45 kW per customer. This option also reduces energy consumption all year long because the lighting load is reduced on all working days with the more efficient equipment. Maximum potential peak demand reduction is estimated at 179 MW.

Conservation Home is a home that includes an efficient refrigerator, efficient air conditioner, more efficient water consumption, and a higher standard of structural insulation and window coatings. The demand saved by these actions is 1.4 kW per customer at a cost of about $2,000. Maximum potential is estimated at 236 MW.

Efficient Heat Pump is an option where an efficient heat pump, with gas backup, is used as replacement for a standard efficiency air conditioner. This reduces the load in the summer by 0.75 kW per customer and reduces the summer air conditioning consumption by 387 kWh. However, 5,479 kWh of winter energy consumption is added which had been served by gas before the heat pump installation. Maximum potential is estimated at 299 MW.

The options in Table 4.7.3.2-1 are compared in detailed simulations to the Supply-Side Base case and then an integrated plan including all or some of these options is developed.

4.7.4 Preliminary Testing of DSM Alternatives

The next step in integrating DSM into the analysis is to analyze each of the options one-at-a-time with the alternative supply-side resources. One problem with evaluating DSM is that one alternative may only have a small effect, particularly at low participation rates. This makes it difficult to see the benefit of the DSM option compared to a larger supply-side option. Also the fact that different options have different potentials make it difficult to compare one alternative to another. In order to minimize these problems it was decided to use a common size of DSM capability for each option so that they could be compared directly with each other. One hundred and sixty MW (160 MW) was selected as the size. Each option is installed in the year 2000. The 160 MW size was chosen since it is the minimum size of the combustion turbines installed in any given year. Thus DSM can be studied at a capacity equivalent to that of a combustion turbine.

Since in this analysis all the DSM options are represented as having the same capability, they can be compared directly on a Total Cost basis. This methodology results in a conservation option yielding a 160 MW demand reduction and a significant energy reduction (e.g., commercial lighting). It also results in the air conditioner "scram" option having a 160 MW demand reduction but no energy reduction. Thus the differences in comparing the results of these options can be attributed to differences in load shape and not size.

The computer runs at a common size comprise the final screening step before an integrated plan is developed. The options that have no positive Total Cost benefit from this analysis are not considered for the integrated plan.

4.7.4.1 Base and Sensitivity Results of the One-at-a-Time DSM Alternative Runs

Table 4.7.4.1-1 lists some results from the six one-at-a-time base case runs. The left four columns summarize the Total Cost. The benefit is the reduction in cost between a case and the lowest cost supply-side-only base case. The right four columns show the effect upon rates over the planning period for the DSM case compared to the supply-side-only base case. Based on this analysis, the cool storage and the conservation home did not have a positive total cost benefit.

The nine other supply-side sensitivity cases (Section 4.7.2) were also run for all seven DSM alternatives. The conservation home did not show a positive total cost benefit in any of the sensitivity cases. In seven of the sensitivities, cool storage had no positive benefit. In the other cases, the benefit was very small. Thus the incremental cost to install cool storage or the conservation home was higher than the savings that were obtained. Therefore, these two options were dropped from the integrated run.

TABLE 4.7.4.1-1
One-at-a-Time Demand-Side Management Analysis
160 MW Fixed Demand Side Case Summary

	Total Cost (Millions of 1990$)				Levelized Rates (¢/kWh)			
	Case	Supply-Side-Only Base	Ben.	Benefits in % Base	Case	Supply-Side-Only Base	Ben.	Ben. in % Base
AC Scram	23,559	23,590	31	.13	4.889	4.896	.007	.14
Int & Leas	23,547	23,590	43	.18	4.887	4.896	.009	.18
Cool Stor	23,606	23,590	(16)	(.07)	4.889	4.896	.007	.14
Com. Light	23,371	23,590	219	.93	4.941	4.896	(.045)	(.92)
Cons Home	23,707	23,590	(117)	(.50)	4.902	4.896	(.006)	(.12)
Eff Ht Pump	22,929	23,590	661	2.80	4.807	4.896	.089	1.82

The case showing the highest Total Cost benefit was the heat pump case with $661 million total cost benefit over the planning period through 2019. This case also has a rate benefit of 0.089¢ per kWh or 1.82% compared to the supply-side-only base case.

The case showing the next highest Total Cost benefit was commercial lighting at $219 million. The peculiarity of commercial lighting is that despite having a high benefit it also has higher rates than the supply-side-only case at 0.92% higher. This says that for the energy remaining after the lighting participants improve the efficiency of their lighting, the rates would be higher. Thus nonparticipants would be paying more than they would have otherwise. The participants, the commercial customers that convert, will have substantially lower electric lighting costs even though their rates will be slightly higher for their remaining electricity.

Table 4.7.4.1-2 is a breakdown of benefits for the utility and the customer. The equations defining the benefits are given in footnotes. Eight DSM programs (two Heat Pump Programs and counting Industrial Interruptible Load and Leased Generation as two), each at 160 MW, were given base case and full sensitivity analysis (nine cases) for each program. This large scale testing formed the basis for determining which DSM programs to retain for the integrated part of the Study and to determine the amount of money available for incentive payments. Only the base case results are given in Table 4.7.4.1-2.

The defining equations shown in the footnotes to the table are fairly straightforward. However, it should be noted that only the incremental (or extra above the Base, whether positive or negative) Customer Other Costs are actually entered into PROVIEW and used in the determination of "Total" Cost. That is, Customer Other Costs for Base are zero by definition and do not enter into the Customer Other Benefit equation. Customer Other Benefits only involve the Customer Other Costs in the sensitivity case, Customer Other Costs being a part of Total Cost for Case.

TABLE 4.7.4.1-2 Analysis of One-at-a-Time 160 MW DSM Base Case Benefits (Millions of 1990 Dollars)							
	Ind Intrup/ Leased	Res AC Scram	Res H.P. Low	Res H.P. High	Com Light	Com Cool Store	Res Cons Home
Utility Benefit	43	31	428	498	(218)	33	(29)
Customer Electric Bill Benefit	0	0	(649)	(764)	470	(5)	132
Customer Other Benefit	0	0	881	1077	(33)	(44)	(220)
TOTAL BENEFIT:	43	31	661	811	219	(16)	(117)

1. Utility Benefit = (Elec Rate of Base - Rate of Case) * Energy of Base

2. Customer Electric Bill Benefit =
   (Energy of Base - Energy of Case) * Elec Rate of Case

3. Customer Other Benefit = (Utility Cost for Case - Total Cost for Case)

   Total Benefit = (Sum 1 + 2 + 3) =
   (Total Cost for Base - Total Cost for Case)

   1 + 2 = Change in Revenue Requirement

   2 + 3 = Total Customer Benefit

Note: Customer Benefits are before any incentives

4.7.4.2 Participation Rates and Integrated Run

Based on the previous analysis, the remaining five DSM options are used in an integrated run. The industrial interruptible load and leased customer generation comprise two options modeled as one. Table 4.7.4.2-1 summarizes additional information needed for the analysis to proceed further.

There is uncertainty associated with the customer participation rates that can be obtained under each of the DSM options and so three different levels were estimated, high, expected, and low. Unlike a supply-side option, DSM relies on the customer's response to incentives, perceived benefits or penalties, and

TABLE 4.7.4.2-1
Demand-Side Management, End-Use Level
Program Participation Assumptions

	PERCENT PART. (%)			SUMMER PEAK MW REDUCTION				PROGRAM COST		BASE UTILITY BENEFIT[3]	
PROGRAM	HIGH LEVEL	BASE (EXP) LEVEL	LOW LEVEL	HIGH LEVEL	BASE (EXP) LEVEL	LOW LEVEL	FREQ. & PAYMENT UNITS FOR COSTS & BENEFITS	ADMIN & RELATIVE RISK COST[2]	INCENT PAY.	BEFORE INCENT	AFTER INCENT
AC Scram	30%	15%	5%	277 MW	139 MW	46 MW	$/Cust yr.	18	35	53	0
Interr. Load & Leased Gen	70 85	45 60	10 25	88 78	56 55	13 23	$/KW-mo $/KW-mo	0.46 0.10	1.57 1.93	2.03 2.03	0.00 0.00
Com. Light	85[1]	60[1]	35[1]	117	72	27	$/bulb on replacement	0.15	0.60 FR 0.30	0.00	-1.05
Eff Ht Pump	30	15	5	89	45	15	one time	150	800	1838	888

[1] For commercial lighting it is assumed that 20% of these participants would put in efficient lighting without incentives. These Free-Riders would receive incentive payments which must be considered from a utility cost perspective. The effective participation rate increase is found by subtracting 20% from the percentage given.

[2] Risk cost is estimated relative to supply-side options.

[3] Benefit results taken from one-at-a-time DSM runs.

the types of people in the targeted customer group. Also the number of "free riders", those who would have participated in the program without incentives, must be estimated. Although studies continue to be done on the relationship between participation level and these other factors, the results are still utility-specific and somewhat unknown. Thus a range is used to at least see the effects of participation level on benefit of the DSM options.

The participation levels in percent and the impacts on summer peak in megawatts are shown in Table 4.7.4.2-1.

The incentives assumed are based on what could be paid from the DSM cases modeled one-at-a-time compared to the supply-side-only base case. These incentive levels then influenced the participation levels that were selected by judgement.

Based on the participation levels selected, an estimate of administrative and program costs is also prepared.

These remaining DSM options are now put into the PROVIEW model as simultaneous options along with the remaining supply-side alternatives and PROVIEW selects the most economical mix. At this step, implementation and program costs are included for each option, as given in Table 4.7.4.2-1. These costs are in addition to the incremental equipment cost which is all that was modeled up to this point.

SECTION 5
FINAL ANALYSES AND RESULTS

5.0 Final Analyses and Results

Three of the four major resource selection steps have been completed at this point in the Study. They are: selecting the best alternatives for a supply-side-only expansion plan, selecting the best demand-side alternatives representing each load shape objective, and testing those demand-side alternatives one-at-a-time for feasibility in conjunction with the supply-side-only plan.

In the fourth and final step, as noted in Figure 3.1-1, the computer program PROVIEW is again employed. PROVIEW selects the optimal, integrated resource mix by sorting through the many, many combinations of expansion resources. These computer runs are the longest because of the extensive alternative list and require five hours on an IBM 486 personal computer. The base and nine sensitivity cases are optimized in this fashion and discussed in this Chapter.

5.1 Integrated Base Case Results

The Integrated Base Case results represent the optimal combination and schedule of resource additions or expansion to the statewide power system and is called the Integrated Base Resource Plan. This major result assumes the base (expected) values of cost and operating parameters. In addition, the chosen total cost evaluation criteria, considering utility, customer, and certain environmental costs, is applied to the optimization task. Both supply-side and demand-side alternatives are selected by PROVIEW for the Integrated Base Resource Plan.

5.1.1 Integrated Base Resource Plan

The Integrated Base Resource Plan for the expansion reporting period of 1991-2010 consists of four demand-side alternatives totalling 292 MW and two types of supply-side alternatives totalling 1680 MW. The Nebraska City Unit #2 alternative is the same resource type as the 600 MW conventional coal unit alternative but can be installed at a reduced cost because it is a second unit at an existing site. The schedule and totals for these integrated base additions are presented in a side-by-side comparison to the base supply-side-only expansion plan in Tables 5.1.1-1 and 5.1.1-2. Note that the heat pump additions are phased in over a 15-year period and the other three DSM programs are phased in over 5-year periods. The resource additions selected by the Study, including the load-side study DSM additions having 15% reserve credits, are shown in Figure 5.1.1-1.

Table 5.1.1-3 shows in effect a "balance sheet" of the increased load obligations of the statewide system projected for the next 20 years and the integrated resource changes, up and down, which in the net satisfy those increased obligations. Appendix B and Table 5.1.1-2 are used as background to this summary "balance sheet".

Table 5.1.1-3 shows that 2052 MW of increases in load obligation (including 268 MW for reserves) and 638 MW of capacity retirements are anticipated by the Nebraska utilities. That is, during the next twenty years, new resources are needed 76% for load growth and 24% for generation capacity retirements. As Nebraska generation continues to age and, if load growth remains low, new resources will be needed increasingly to replace capacity being retired.

Table 5.1.1-4 lists the resource categories expected to meet the load growth and the retirement obligations listed above.

FIGURE 5.1.1-1
INTEGRATED BASE CASE RESOURCE ADDITIONS

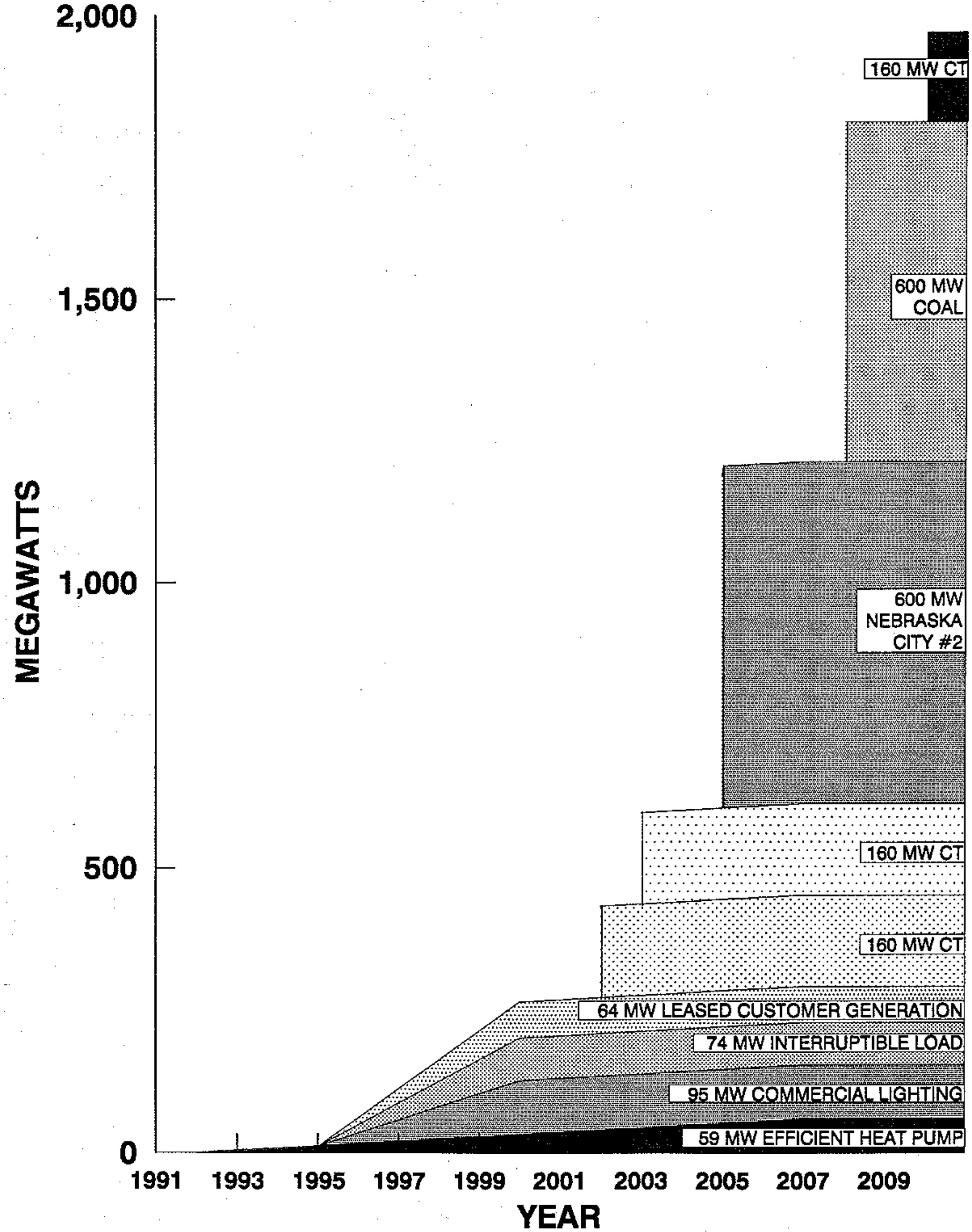


TABLE 5.1.1-1
20-Year Base Case Expansion Plans

Year	Supply-Side-Only Base	Integrated Base Resource Plan[1]				
		Demand-Side Management Programs				Supply-Side
		Leased Gen.	Interr. Load	Comm. Lighting	Eff Ht Pump	
1991						
1992						
1993					4 MW	
1994					4 MW	
1995					4 MW	
1996		13 MW	15 MW	19 MW	4 MW	
1997		13 MW	15 MW	19 MW	4 MW	
1998		13 MW	15 MW	19 MW	4 MW	
1999		13 MW	15 MW	19 MW	4 MW	
2000	160 MW CT	12 MW	14 MW	19 MW	4 MW	
2001	160 MW CT	64 Total	74 Total	95 Total	4 MW	
2002	160 MW CT				4 MW	160 MW CT
2003					4 MW	160 MW CT
2004	600 MW Neb City #2 Coal				4 MW	
2005					4 MW	600 MW Neb City #2 Coal
2006					4 MW	
2007					3 MW	
2008	600 MW Coal				59 Total	600 MW Coal
2009						
2010	160 MW CT					160 MW CT

[1] All DSM options are referenced to the generator bus (with 15% system losses). All load-side DSM options include 15% reserve credit.

Table 5.1.1-2 Installation and Cost Summary for the Base Cases[1]		
	If Only Supply-Side Considered	Integrated Base Resource Plan
Makeup of 20-Year Expansions:		
Study DSM	---	**292**
Coal	1200	**1200**
Combustion Turbines	640	**480**
TOTAL MW Additions	1840	**1972**
30-Year Results (1990$)		
Net Present Value (M$)	$23,590	**$23,291**
NPV Retail Rate (¢/kWh)	3.258¢	**3.228¢**
Levelized Retail Rate	4.896¢	**4.850¢**

[1] Base Case Expansion Plans are given in Table 5.1.1-1.

TABLE 5.1.1-3
Base Case "Balance Sheet" of Increases in Obligations and Resources (1991-2010)

MW	Load Obligations	MW	Resources
1780	Increases in Peak Load after accounting for DSM reductions assumed in the load forecast but before the Study DSM reductions		**Pre-Study Assumptions**
4	Increased External Firm Sales	-476	Fort Calhoun Retirement
268	Increased 15% Reserve Obligation	-162	Small Unit Retirements
		25	North Omaha Uprate
		24	Increased External Firm Purchases (Tri-State)
		4	Reserves Available on External Firm Purchases
		-585	**Subtotal Pre-Study**
			Integrated Base Resource Plan from the Study
		1200	Coal Unit Additions
		480	C.T. Additions
		64	DSM Generation Additions
		198	DSM Load-Side Additions
		30	DSM Reserve Credit (15%)
		1972	**Subtotal Study Resources**
		1387	**Total Net Resource Increases**
		665	**Use of Surplus Capacity[1]**
2052	**MW Total Obligation Increases**	**2052**	**MW Designated Resources**

[1]Surplus capacity reduced from 856 MW in 1991 to 191 MW in 2010.

TABLE 5.1.1-4
Resource Categories for Meeting Nebraska's 20-Year Needs

665 MW	25%	Use of Surplus Capacity
53 MW	2%	Planned Resource Increases
		Integrated Base Resource Plan
1680 MW	62%	Supply-Side Additions
292 MW	11%	DSM Additions
2690 MW	100%	TOTAL

5.1.2 Cost Components of the Integrated Base Resource Plan

As reported in Section 5.1.1, there are three types of supply-side resources in the Integrated Base Plan: combustion turbines, Nebraska City #2, and 600 MW coal units. The total cost of each of these resources is shown in Figure 5.1.2-1.

At very low capacity factors, the baseload units are approximately three times as costly as combustion turbines. At approximately 20% capacity factor, the CT and the large coal options have nearly equal costs. By about 60% capacity factor, where a baseload unit would typically operate, it is approximately only one-half as costly as the CT if the CT operated at such a high capacity factor.

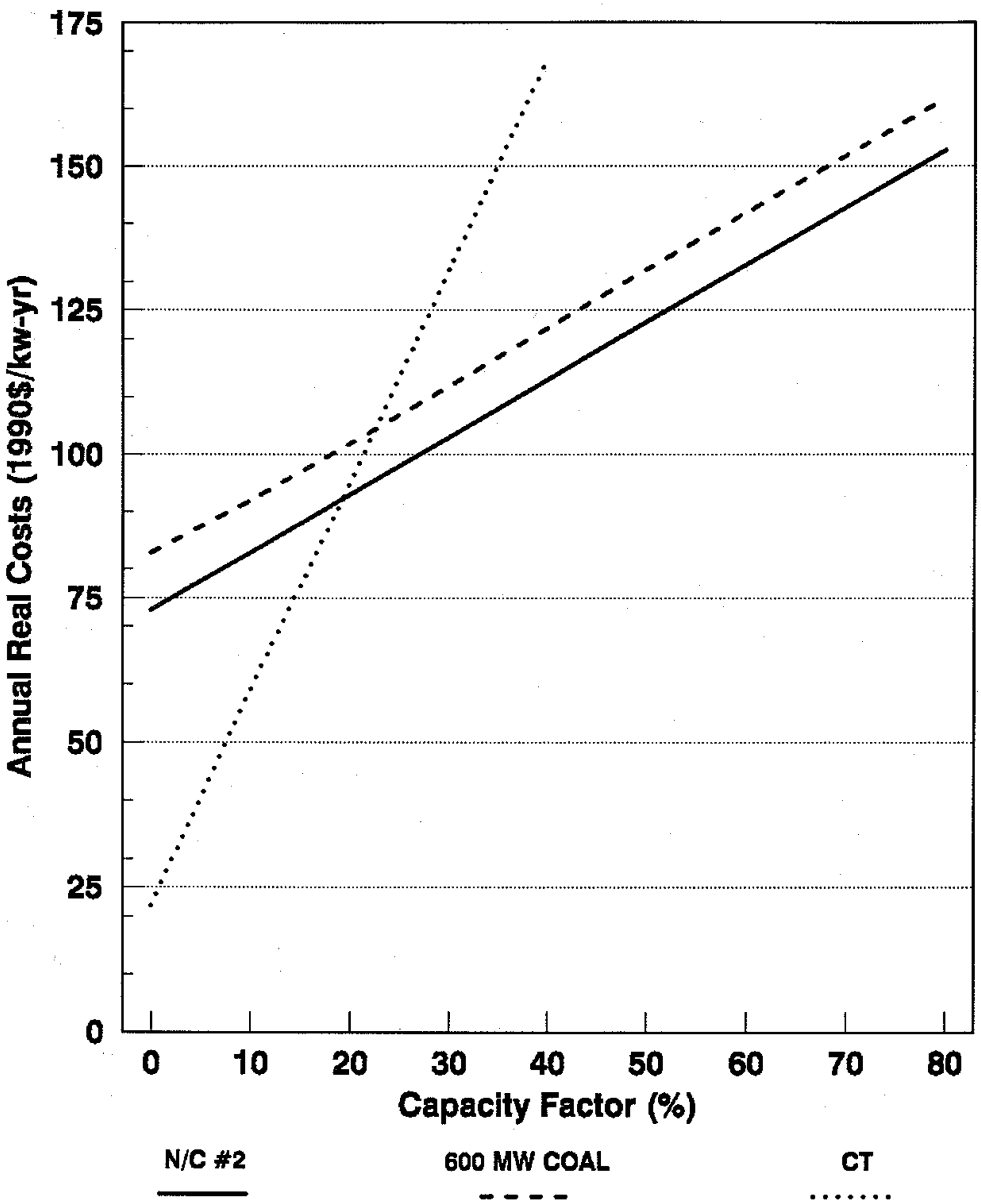
This comparison demonstrates why a proper resource "mix" is important for economical reasons. The loads throughout the year vary from peaking to baseload type such as air conditioning to lighting, respectively. DSM resources also have these characteristics as described in Section 5.1.3.

The levelized cost components of the three supply-side resources are depicted in Figures 5.1.2-2, 5.1.2-3, and 5.1.2-4. For these three resources, fuel cost is the only cost component assumed to escalate at a rate other than inflation. To best incorporate the effects of fuel escalation prior to the critical time of the study period, fuel costs in the year 2005 are represented and converted to real 1990$. The special environmental cost component includes the portions of the other cost categories that are dedicated to environmental protection. Several key observations are apparent:

- The coal units have high fixed costs such as capital investment in coal handling facilities whereas CT's have a much lower capital investment.

FIGURE 5.1.2-1

Cost of Supply-Side Resources in the Integrated Base Plan



Cost Components of Supply-Side Resources

FIGURE 5.1.2-2
Nebraska City #2

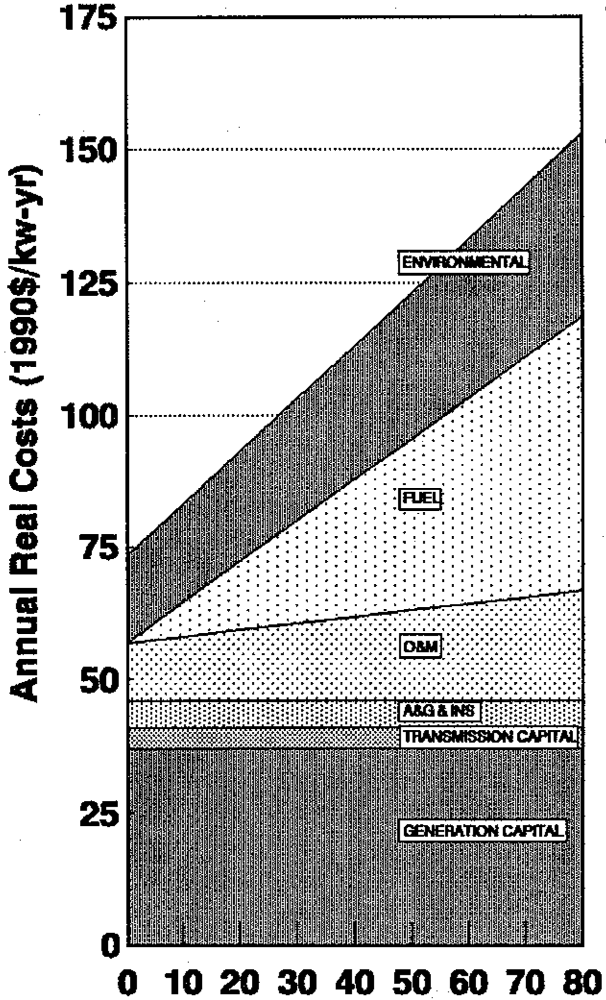


FIGURE 5.1.2-3
600 MW Coal

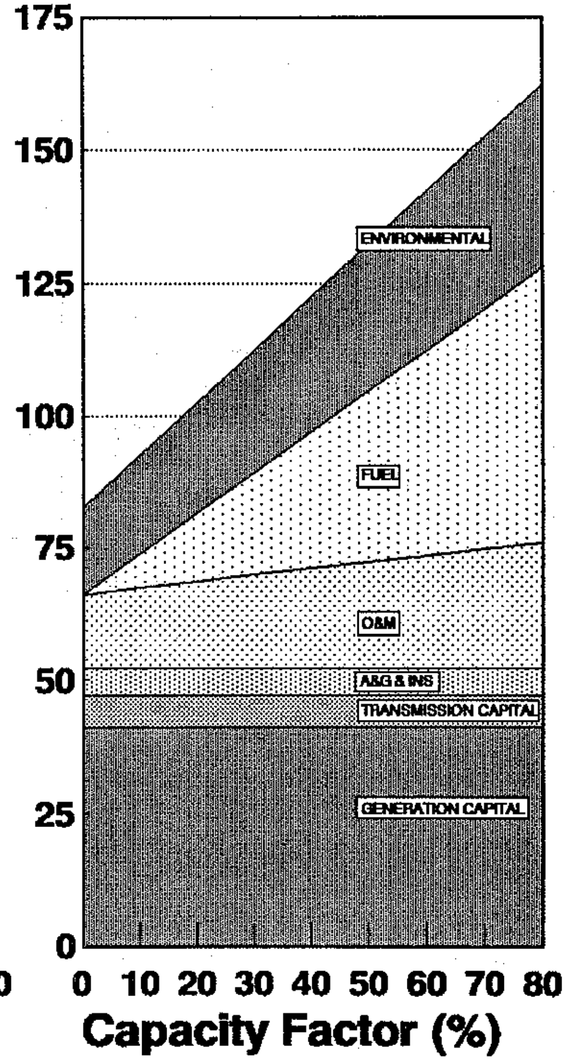
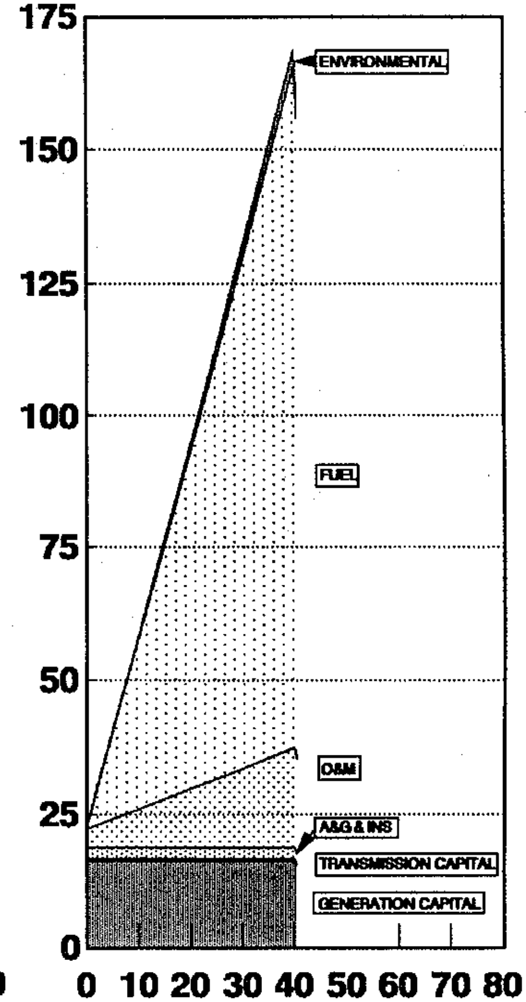


FIGURE 5.1.2-4
Combustion Turbine



- Being a second unit at the site, Nebraska City Unit #2 is somewhat less costly than the 600 MW Coal Unit cost shown as the average cost of first and second units at a site.

- The coal fuel cost is considerably less than the natural gas fuel cost for the CT's. Not only is the raw supply of natural gas fuel much more limited than for coal, resulting in a greater cost, but the combustion turbine technology has a higher heat rate (less efficient) than a coal-fired boiler.

- The environmental-related costs are significant for today's modern coal-fired generating equipment and its operation. Such costs include flue gas desulfurization equipment (scrubbers), baghouses, low-NO_x burners, cooling towers, ash and sludge disposal, waste-water treatment equipment, etc. Also some allowance is included for uncertain future environmental costs. These costs total more than 20% of the cost to generate coal-based electricity at a 60% capacity factor.

- The environmental-related cost associated with combustion turbine operation as shown in Figure 5.1.2-4 is quite small. However, approximately 9% of the installation cost is related to water-injection equipment used for the control of NO_x emissions. This contribution for environmental protection is not depicted because water injection also allows operation at a higher level thereby providing a direct economic return on that utility investment.

5.1.3 Demand-Side Management in the Integrated Base Resource Plan

As indicated in Table 5.1.1-4, the 20-year resource needs are for 2690 MW. These needs are satisfied in the Integrated Base Resource Plan 27% by the combination of existing surplus capacity and currently-planned miscellaneous increases with the remainder being 62% supply-side and 11% demand-side resources. The DSM programs selected constitute 292 MW.

5.1.3.1 Overall Effects of DSM

The effects of the 292 MW of DSM resources (262 MW before applicable reserve credits) are small compared to the overall load of up to 6000 MW as demonstrated in Figures 5.1.3.1-1 and 5.1.3.1-2. The curves depict Nebraska's hourly load patterns on the summer and winter peak days in the year 2007. The year 2007 is shown because that is the first year all study DSM is in place. During the peak hours the individual DSM effects from efficient heat pumps, commercial lighting, interruptible load, and leased customer generation are shown on expanded scales. In the peak portion of the graph, industrial interruptible load can be used to clip off 64 MW of load and leased generation can be used to "effectively" clip off another 64 MW. The leased generation is brought on line at peak. Load is not actually removed but it is "effectively" removed by the customer's generation. It is shown on the demand-side in this way for simplicity of modeling and because the customer is involved.

Because of Nebraska's heavy air-conditioning and irrigation loads, the peak loads occur in the hottest hours of July and August and, sometimes, late June or early September. At the peak hour, the efficient heat pump program contributes 51 MW of load reduction (before reserve credit) and commercial lighting contributes 83 MW. A commercial lighting reduction of 102 MW actually occurs at other times but the 83 MW amount at peak is the amount of most importance.

At the other extreme, the very lowest load levels occur in the overnight hours of Spring and Fall when the weather is moderate and there are no heating or cooling loads. In 2007, the loads never get below approximately 1600 MW.

The leased generation and interruptible load resources are purely peaking in nature and are usually only applied at peak load. For the interruptible load to provide load relief, the load must be on. If the load is of industrial type with many hours of operation, it could then, whenever operating, provide load relief during emergencies even if peak load is not occurring. The other

FIGURE 5.1.3.1-1
DSM EFFECTS AT SUMMER PEAK

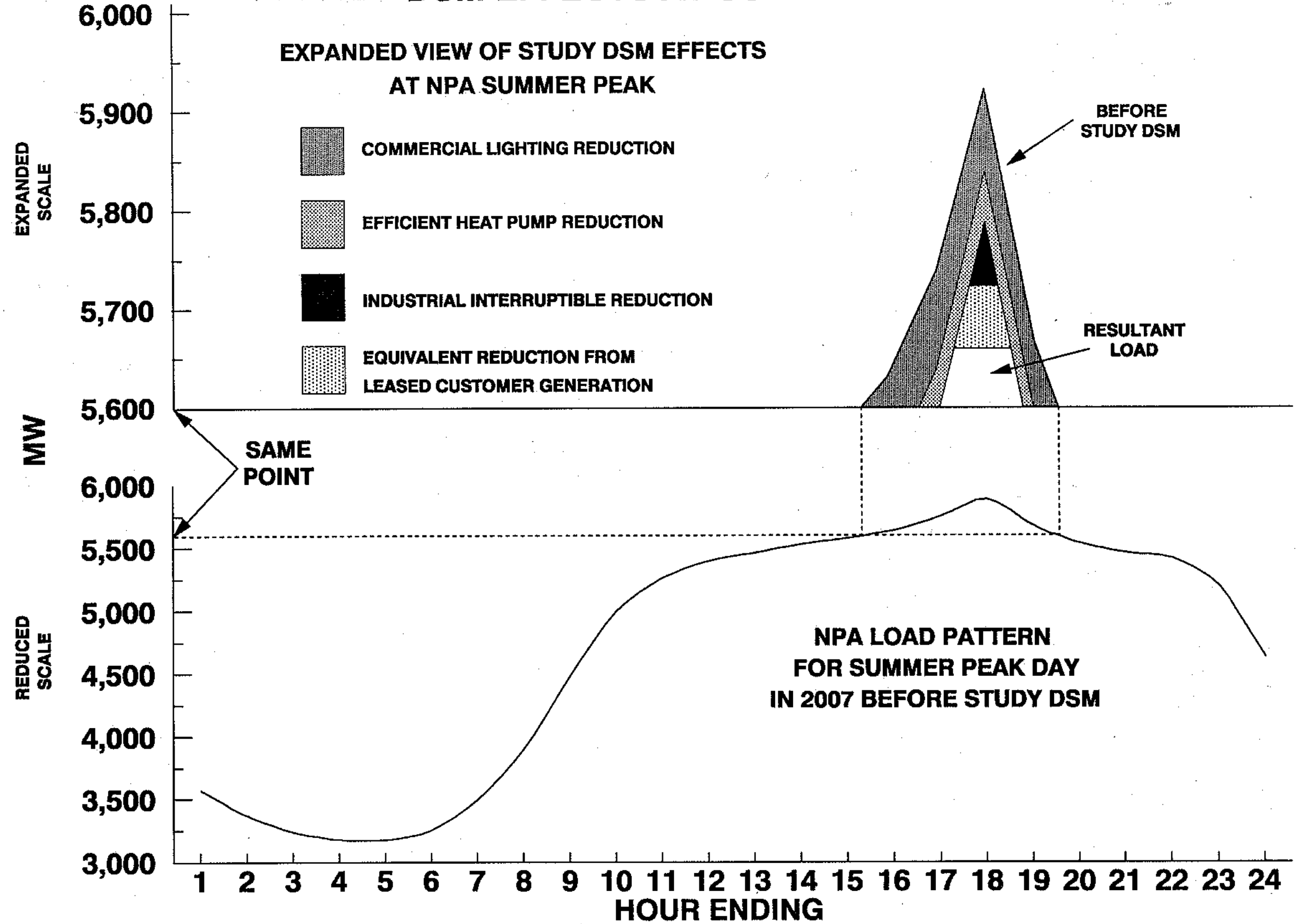
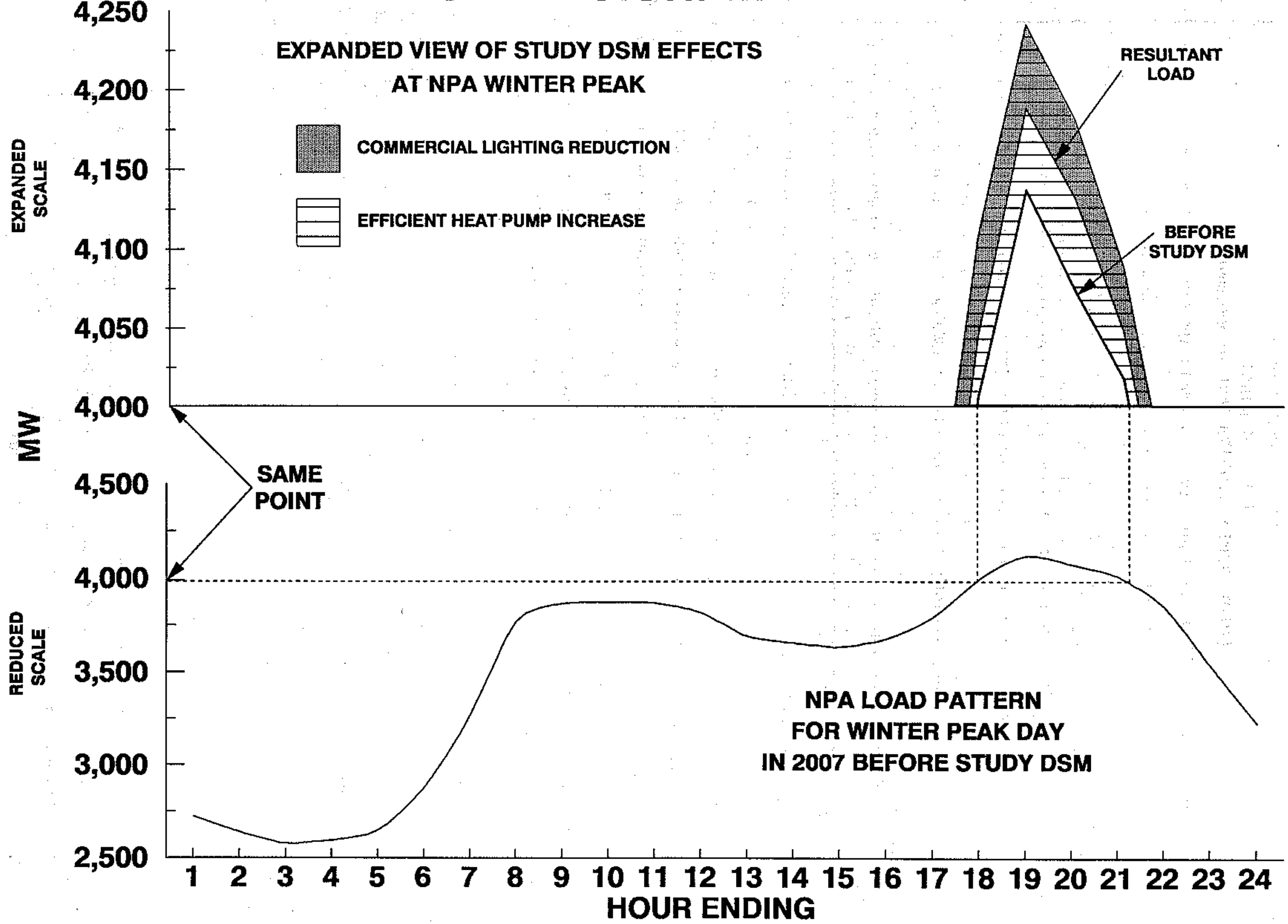


FIGURE 5.1.3.1-2
DSM EFFECTS AT WINTER PEAK



interruptible DSM resource, AC Scram (not selected), could not provide this emergency help to the same extent. The air conditioning loads would need to be occurring. Similar to industrial interruptible load, leased generation could provide load relief at nearly any time for emergencies.

Commercial lighting DSM programs could provide a resource of a baseload nature because such lighting loads are on, at least to some extent, many hours of the year. Commercial lighting efficiencies reduce the system load to some extent at all load levels. The summer load-reduction effects of the efficient heat pump are only present at the higher loads when air conditioning is present. The other aspect of the efficient heat pump program is to add significant amounts of heating load during the winter months. The heating load added at winter peak is not great, however, because the heat pumps are partially "backed up" by gas furnaces.

The DSM resources in the Integrated Base Resource Plan replace and delay the need for some combustion turbine capacity in the Supply-Side-Only Plan as shown in Table 5.1.1-1. The 600 MW Nebraska City #2 coal unit is also deferred one year but the other 600 MW coal unit is not deferred. That unit is relatively fixed to the year 2008 because of the assumed retirement of the Fort Calhoun Nuclear Station, a large baseload unit.

The Integrated Base Resource Plan reduces costs by approximately $299 million ($1990 P.V.) (or 1.3%) over the Supply-Side-Only Base Resource Plan during the 30-year planning period as shown in Table 5.2.1-2. In addition, the levelized retail rates associated with the Integrated Base Resource Plan are 4.85¢/kWh (or 0.9% less). This amount of rate reduction is before the DSM incentive payments are factored into the rates. After including these costs, the levelized integrated base rate is 4.87¢/kWh (or 0.5% less than the rate for the Supply-Side-Only Base Plan).

As a result of the changes in the resource plan and from the "reshaping" of system load patterns, as mentioned above, several 30-year effects related to the DSM resources can be quantified as shown in Table 5.1.3.1-1.

TABLE 5.1.3.1-1 **Summary of DSM Effects (1990-2019)**
Defers the need for 292 MW (15%) of new supply-side resources.
Decreases energy production requirements by 2619 GWH (0.33%).
Decreases retail energy sales by 2407 GWH (0.33%).
Increases SO_2 emissions by 7,900 (0.5%) tons. (due to deferring new, very clean baseload units).
Reduces 30-year total cost by $299 million (1990 P.V.) (1.3%).
Reduces levelized retail rates to 4.85¢/kWh (0.9%) before incentive payments and to 4.87¢/kWh (0.5%) after considering incentive payments.
Saves approximately 900,000 tons of coal, uses 50,000,000 more gallons of oil, and saves 22,000,000 MCF of natural gas.

The DSM effects quantified in Table 5.1.3.1-1 are in addition to any effects from extensions of already existing DSM programs, notably load control. Also, there are some considerations, in addition to these quantifiable effects, that relate to the new DSM programs. For example, the applicability of these programs varies by individual utility. Besides the variance in the need for new resources among the individual utilities, DSM feasibility varies with each individual utility's existing load pattern. The dependability of the DSM programs is somewhat open to question because it involves the interest and cooperation of the customers, while most such customer factors are essentially beyond the utility's control. Some of the programs have long lead times and short lifetimes. Passing benefits on to one customer group through a DSM program can have some side effects on other non-participating customers.

5.1.3.2 Utility and Customer Effects of DSM

The four DSM programs in the Integrated Base Resource Plan represent all three possible incentive arrangements between the utility and its participating DSM customers as shown in Table 4.7.4.2-1. For the industrial interruptible load and leased generation programs, all of the utility benefit is assumed to be used up in the utility's costs for administration, risk, and incentive payments. In the commercial lighting program these types of utility costs exceed any benefits and the utility loses $1.05 per bulb installed under the program. On the other hand, the efficient heat pump is beneficial enough for the utility to be able to meet all associated costs and yet retain $888 of benefit per installation.

Using both Tables 4.7.4.2-1 and 4.7.4.1-2, participating customers in the four DSM programs receive the net benefit of both customer benefit portions in the latter table plus the incentive payments as indicated above and in the former table. All of the four DSM programs selected in the Integrated Base Resource Plan result in positive benefits to the participating customer.

That the customers will require benefits in order to participate is very likely in most cases. This is especially true because, in most cases, the customer must take on some added burden such as, allowing equipment to be controlled off, changing out equipment, providing access for the utility, sacrificing some flexibility or, in some other way, perhaps living with a lesser degree of electrical service.

These factors, or added burdens to the customers, result in concerns about the ongoing attitude of the DSM customers and their willingness to continue providing their DSM service to the utility. For example, even if the Integrated Base Resource Plan had selected the AC scram option, there would be some concern that the incentive payment available may be too small to maintain customer participation.

5.1.4 Environmental Implications of the Integrated Base Resource Plan

For simplicity, the environmental results of the Integrated Base Resource Plan are presented in Section 5.2.4 with the results of the sensitivity cases. In summary, the Integrated Base Resource Plan meets the requirements of the 1990 Clean Air Act Amendments as well as all other current environmental requirements. A significant portion of future power cost is attributable to protection of the environment as noted in Section 5.1.2. As stated in Section 5.1.3.1, the integration of DSM programs results in a slight increase in emissions, particularly SO_2, because of the deferral of Nebraska City Unit #2.

5.1.5 Transmission Implications of the Integrated Base Resource Plan

During the reporting period (1991-2010) of the Integrated Base case, two 600 MW coal units are added; the other supply-side resources added during this period are CTs. Of the two coal unit additions, Nebraska City #2 is installed first; the second such unit would be located at a new site. For this Study, it is assumed that either of two previously-identified sites would be used: one near Lincoln, and the other in central Nebraska.

The required additional transmission facilities associated with the Integrated Base Resource Plan are shown on the map in Appendix E. The construction of transmission facilities added in conjunction with Nebraska City #2 were estimated to cost approximately $47,000,000 (in 1990 dollars). Transmission facility costs for the two future large baseload unit sites were estimated as follows: about $27,000,000 for the first unit at the Lincoln site, and about $121,000,000 for the first unit at the central Nebraska site (all 1990 dollars). The selection between the two future sites would also be influenced by the costs of rail transportation of coal, the costs of electric demand and energy losses, and environmental considerations.

The combustion turbine additions in the Integrated Base Resource Plan would be substantial (480 MW by 2010), but these small units could be installed at distributed sites closer to the load centers. This would minimize the requirements for transmission facility additions.

DSM alternatives do not generally require transmission additions. However, even if the DSM resources are not implemented, the impact on the base case transmission expansion plan would be negligible -- since the plan without DSM additions would simply include 160 MW of additional CTs.

5.1.6 Rates Under the Integrated Base Resource Plan

Calculation of retail rates is not a principal objective of the Study because Total Cost, rather than rates, was chosen as the Evaluation Criteria.

However, reasonable estimates of rates were made for the purpose of determining trends and to note relative rate effects from DSM programs.

As noted in Section 5.1.3.1, the ultimate rate must include the revenue requirements to pay DSM incentives in addition to program administration and risk costs. In most instances, the rates calculated in the Study do not include the cost of incentives. However, the rates for the Integrated Base case displayed in Figure 5.1.6-1 do include the costs of such DSM incentives.

In Figure 5.1.6-1, the retail rates are shown in nominal, or actual-year dollar, terms and compared to the general inflation rate of 5% per year. Rate increases are expected but at a level noticeably less than inflation. Note particularly there is a several-year trend where the estimated rate and the inflation rate diverge, primarily, because resources are surplus. The later "paralleling" with some increases is due to the installation of new resources.

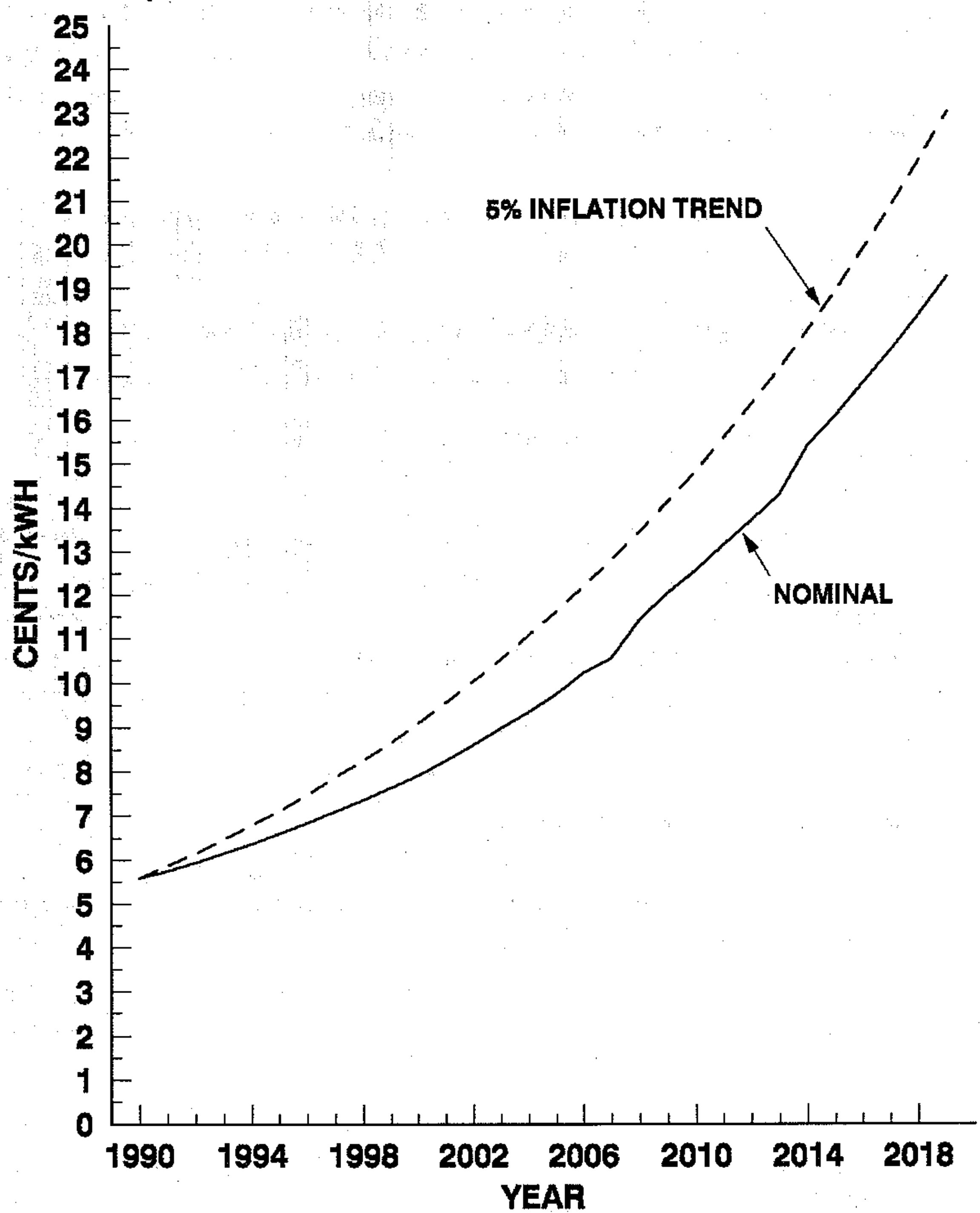
5.2 Sensitivity Case Results

Sensitivity cases were originally run with supply-side-only options, as discussed in Section 4.7.2. These cases serve several purposes. First they allowed the Integrated Planning Task Force to eliminate some of the supply-side options from further consideration because they were never selected, even under the different uncertainties represented by the sensitivity cases. Secondly it gave an indication of the impact of the different uncertainties on the resources selected in the lowest cost expansion plan for each sensitivity case. Finally, the impact of the uncertainties on the total cost of these plans is determined. Armed with this additional knowledge, the planner can note which uncertainties are the most critical to the Integrated Base Resource Plan. This knowledge also suggests which options one can anticipate using to respond if the future is trending in a direction significantly different from the base assumptions. Finally, supply-side or demand-side options that fare best under a large number of sensitivity cases would also be looked upon more favorably to meet future energy needs.

FIGURE 5.1.6-1

ESTIMATED AVERAGE RETAIL RATE IN NOMINAL TERMS

(INTEGRATED BASE CASE AFTER DSM INCENTIVES PAID)



In the integrated cases, demand-side options were made available for selection along with the supply-side options. The value of running sensitivity cases for the integrated plans is basically the same as when studying the supply-side options only. An additional uncertainty exists with the demand-side options. Since they are dependent on the response of customers to incentives and education, the level at which customers will actually participate in DSM programs is uncertain. Consequently, two additional sensitivity cases, high and low customer participation rates, were added for the integrated cases.

More information concerning the sensitivity cases run on the integrated expansion plans is presented in the following sections. Note that these cases represent uncertainties about the future in six basic areas: 1) environmental impacts, 2) load growth, 3) fuel costs, 4) generating unit capital costs, 5) discount rate, and 6) customer participation in demand-side programs.

5.2.1 Expansion Plans of the Sensitivity Cases

The expansion plans of the base and sensitivity cases are shown on Tables 5.2.1-1 for the supply-side-only runs and 5.2.1-2 for the integrated case runs. These tables also include the total capacity additions of supply-side resources and demand-side programs by type for the reporting period. Other results shown are the total costs, the net present value retail rate, the levelized rate and the cost ranking of the cases.

5.2.2 General Sensitivity Case Findings

Perhaps the most dramatic results occur in the area of the total cost changes created by the sensitivity cases. This ranking is shown on Table 5.2.1-2. The DSM programs produce cost changes of 0.4% to 2.3% (a range of 1.9%) from the cases without DSM for programs equivalent to 5% to 26% of the total capacity needed in the reporting period.

Table 5.2.1-1

Supply-Side-Only Optimization Cases

	Base Case	HR 4805 Carbon Tax	Clean Coal	Fuel Prices: Gas +30%	Fuel Prices: Coal +33%	Capital Prices: CT +39%	Capital Prices: Coal +20%	High Load Forecast	Low Load Forecast	12% Discount*
YEAR: 1998								CT 160		
1999								NC 600		
2000	CT 160	CT 160	CT 160	CT 160	CT 160	CT 160	CT 160			CT 160
2001	CT 160	CT 160	CT 160	NC 600	CT 160	CT 160	CT 160			CT 160
2002	CT 160	CT 160	CT 160		CT 160	CT 160	CT 160	CT 160		CT 160
2003								CT 160		
2004	NC 600	NC 600	IGCC 500		NC 600	NC 600	NC 600	CT 160		CT 160
2005								CT 160		CT 160
2006				CT 160				CT 160		CT 160
2007				CT 160				Coal 600	CT 160	
2008	Coal 600	Coal 600	IGCC 500 CT 160 CT 160	Coal 600	Coal 600	Coal 600	Coal 600	Coal 600	NC 600	NC 600
2009										Coal 600
2010	CT 160	CC 150		Coal 600	CT 160	Coal 600	CC 150	CT 160		
Coal	1200	1200	1000	1800	1200	1800	1200	1800	600	1200
C.T.	640	480	800	480	640	480	480	1120	160	960
C.C.	0	150	0	0	0	0	150	0	0	0
TOTAL MW Additions	1840	1830	1800	2280	1840	2280	1830	2920	760	2160
NPV Cost (M$)	$23,590	$26,796	$25,011	$23,769	$24,546	$23,645	$23,718	$25,140	$22,165	$15,256
Ranking	2	9	7	5	6	3	4	8	1	
Change From Base Case	n/a	$3,206	$1,421	$179	$956	$55	$128	$1,550	($1,425)	($8,334)
% Change from Base Case		13.59%	6.02%	0.76%	4.05%	0.23%	0.54%	6.57%	(6.04%)	
NPV Retail Rate (c/kWh)	3.258	3.701	3.455	3.283	3.391	3.266	3.276	3.070	3.480	2.107
Ranking	2	9	7	5	6	3	4	1	8	
Levelized Rate (c/kWh)	4.896	5.561	5.191	4.933	5.094	4.907	4.922	4.613	5.229	4.925
Ranking	2	9	7	5	6	3	4	1	8	

* Costs not comparable to other scenarios which use 8% discount rate.

Table 5.2.1-2

Integrated Resource Plan Cases

	Base Case	Low Case	High Case	HR 4805 Carbon Tax	Clean Coal	Fuel Prices Gas +30%	Fuel Prices Coal +33%	Capital Prices CT +39%	Capital Prices Coal +20%	High Load Forecast	Low Load Forecast	12% Discount*
YEAR: 1993	H.P. 59	H.P. 20	H.P. 118	H.P. 59	H.P. 59	H.P. 59	H.P. 59	H.P. 59	H.P. 59	H.P. 59	H.P. 59	H.P. 59
1994										IND 138 LIGH 95		
1995												
1996	IND 138 LIGH 95	IND 44 LIGH 36	IND 205 LIGH 154	IND 138 LIGH 95	IND 138 LIGH 95 AC SC 183	IND 138 LIGH 95	IND 138 LIGH 95	IND 138 LIGH 95	IND 138 LIGH 95			IND 138 LIGH 95
1997												
1998												
1999										CT 160		
2000										CT 160		
2001		CT 160								NC 600		
2002	CT 160	CT 160	CT 160	CT 160		NC 600	CT 160	NC 600	CT 160			CT 160
2003	CT 160	NC 600		CT 160	CT 160		CT 160		CT 160		LIGH 95	CT 160
2004										CT 160		
2005	NC 600		NC 600	NC 600	IGCC 500	CT 160	NC 600		NC 600	CT 160		CT 160
2006										CT 160		CT 160
2007								CT 160		Coal 600		CT 160
2008	Coal 600	Coal 600	Coal 600	Coal 600	IGCC 500	Coal 600	Coal 600	Coal 600	Coal 600	Coal 600	NC 600	NC 600
2009		CT 160	CT 160		CT 160	Coal 600		CT 160			CT 160	
2010	CT 160	CT 160		CT 160			CT 160		CT 160			Coal 600
DSM	292	100	477	292	475	292	292	292	292	292	154	292
Coal	1200	1200	1200	1200	1000	1800	1200	1200	1200	1800	600	1200
C.T.	480	640	320	480	320	160	480	320	480	800	160	800
C.C.	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL MW Additions	1972	1940	1997	1972	1795	2252	1972	1812	1972	2892	914	2292
NPV Supply-Side-Only (M$)	$23,590	$23,590	$23,590	$26,796	$25,011	$23,769	$24,546	$23,645	$23,718	$25,140	$22,165	$15,256
Ranking	2	2	2	9	7	5	6	3	4	8	1	
Integrated Resource Case	$23,291	$23,486	$23,051	$26,471	$24,697	$23,413	$24,246	$23,330	$23,425	$24,817	$21,908	$15,105
% Change from Base Case	0.00%	0.84%	(1.03%)	13.65%	6.04%	0.52%	4.10%	0.17%	0.57%	6.55%	(5.94%)	
Ranking	2			9	7	4	6	3	5	8	1	
Change From Supply-Side	($299)	($104)	($539)	($325)	($314)	($356)	($300)	($315)	($293)	($323)	($257)	($151)
% Change from Supply-Side	(1.27%)	(0.44%)	(2.28%)	(1.21%)	(1.25%)	(1.50%)	(1.22%)	(1.33%)	(1.24%)	(1.29%)	(1.16%)	(0.99%)
NPV Retail Rate (c/kWh)	3.228	3.249	3.191	3.669	3.423	3.245	3.360	3.233	3.246	3.043	3.439	2.093
Ranking	2			9	7	4	6	3	5	1	8	
Levelized Rate (c/kWh)	4.850	4.882	4.795	5.512	5.143	4.875	5.049	4.858	4.878	4.571	5.166	4.893
Ranking	2			9	7	4	6	3	5	1	8	

* Cost not comparable to other scenarios which use 8% discount rate.

** Load-Side DSM Programs Include 15% Losses and 15% Reserve Margin Requirements. Generation-Side DSM Programs include 15% Losses Only.

The Capital Cost price cases produced a range of total cost change of only 0.6%. The Fuel Cost cases produced a range of 4.1% in the total cost. The Load Forecast cases produced a range of 12.5% in total cost. One would normally expect the largest total cost changes from the Load Forecast changes. However, the Environmental cases produced a range in total costs of 13.6%. The HR 4805 Carbon Tax case increases total costs 13.6% primarily through a potential tax of $15 per ton of coal for CO_2 emissions. This assumption is based on proposed legislation introduced at the federal level. Even though the costs to the utility and its ratepayers from the HR 4805 Carbon Tax would be very high, the CO_2 emissions and environmental impacts would not be significantly different. That is, the expansion plans did not change for our study assumptions. Of the Fuel Cost and Capital Price sensitivity cases, only the Coal Fuel Price +33% Case increased total costs more than 0.6%. The Coal Fuel Price +33% case raised total costs 4.1%.

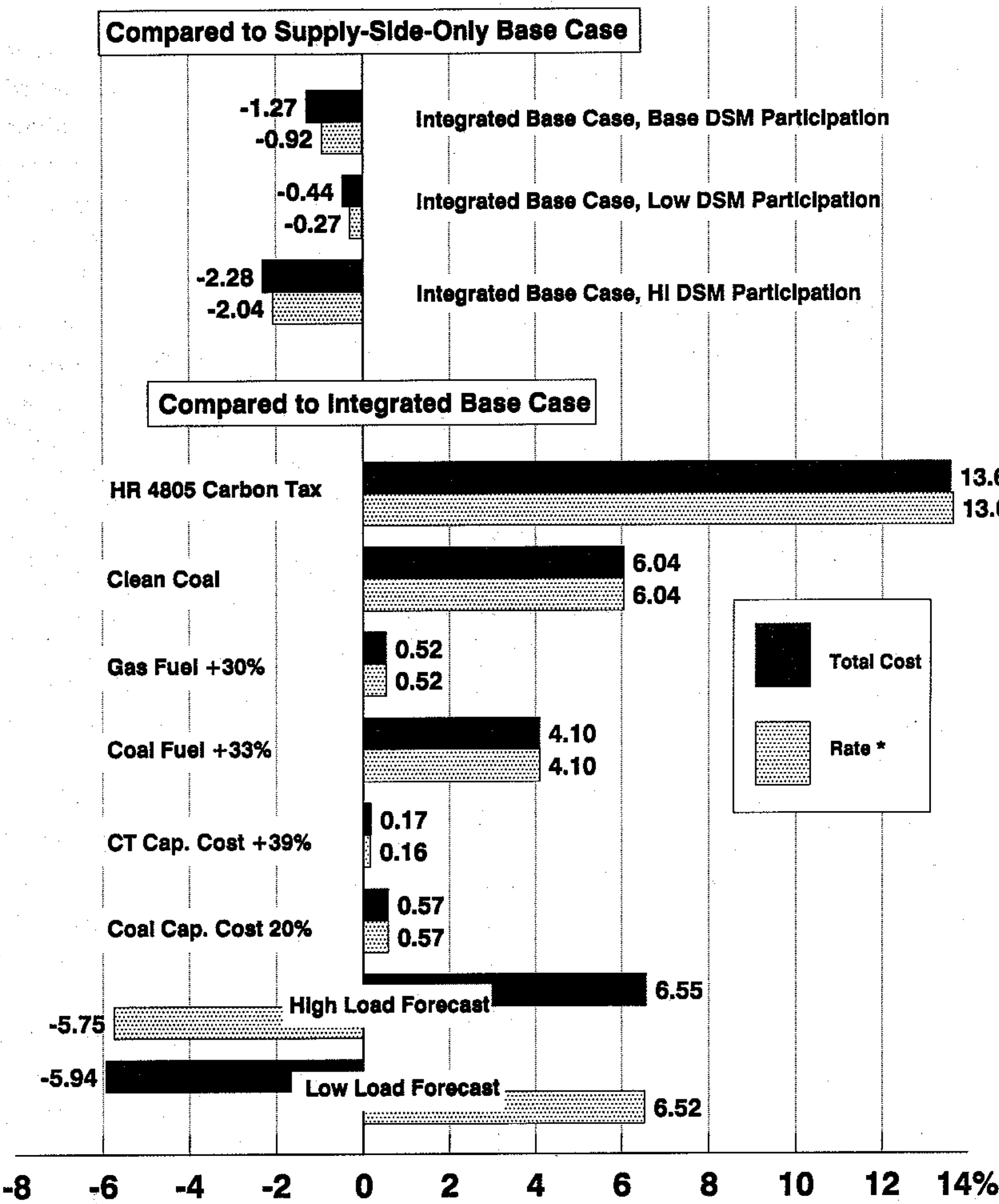
The ranking of the NPV Retail Rates and the Levelized Rate of the sensitivity cases match the ranking of the total costs of the cases except in the Load Forecast cases. This ranking is shown on Tables 5.2.1-1 and 5.2.1-2. The changes in total costs and rates are shown on Figure 5.2.2-1. Compared to the Integrated Base case, the High Load Forecast case has higher total costs but lower rates. The Low Load Forecast case has lower total costs but higher rates. The two cases with the highest rates are the HR 4805 Carbon Tax and the Low Load Forecast cases respectively. The case with the lowest rates is the High Load Forecast case.

5.2.3 Demand-Side Management in the Sensitivity Cases

The heat pump program and the commercial lighting program are selected in all the sensitivity cases. The interruptible load and leased generation programs are selected in all cases except the Low Load Forecast case. The air conditioner scram program is selected only in the Clean Coal case.

FIGURE 5.2.2-1

TOTAL COSTS AND RATES FOR SENSITIVITY CASES AS A PERCENTAGE OF BASE CASE VALUES (%)



* Rate Effect is computed before the cost of incentive payments is factored in.

The DSM programs delay supply-side resources in all cases and, for the expected participation rates, reduce the cost of the cases from 1.0% to 1.5%. The low and high participation rates for DSM go outside this range with total cost reductions of 0.4% and 2.3% respectively.

In terms of capacity mix, the DSM options replace combustion turbine units in all except three cases. These three exceptions are the HR 4805 Carbon Tax case, the Coal Capital Cost +20% case, and the Low Load Growth case. In the HR 4805 Carbon Tax case and in the Coal +20% case, the DSM programs replace a combined cycle unit. In the Low Load Forecast case, units are delayed but not replaced. Uniquely, in the Combustion Turbine Capital Cost +39% case, DSM replaces a 600 MW coal unit. Not all of these replacements are MW for MW because the total capacity added for the base load forecast during the reporting period varies from 1795 MW to 2292 MW depending upon how close to the end of the reporting period the last 600 MW coal unit is added.

When compared to supply-side-only cases, the DSM programs have varying impacts on the year that Nebraska City Unit #2 is added. DSM programs do not delay NC#2 in the Low Load Forecast case or the 12% Discount case. DSM programs do delay NC#2 by one year in the Integrated Base case (compared to the Supply-Side-Only Base case), both Environmental cases, both Fuel Price cases, and the Coal Capital Cost +20% case. The DSM programs delay NC#2 by two years in the High Load Forecast case. NC#2 is advanced one year by the DSM programs in the Low Participation Rate case and by two years in the Combustion Turbine Capital Cost case.

5.2.4 Environmental Implications of the Sensitivity Cases

Cumulative SO_2 emissions, shown in Figure 5.2.4-1, vary for several of the five selected cases. The Integrated Clean Coal case reduces SO_2 emissions by 4.4% at an increase in cost of 6.0%. The Integrated Gas Fuel Price + 30% case reduces SO_2 emissions by 6.8% over the Integrated Base case at a total cost increase of 0.5%.

The DSM options actually increase SO_2 emissions slightly (0.5%) compared to the Supply-Side-Only case while reducing total costs 1.3%. The increase in load factor of over 0.6% with DSM during the planning period, shifting some energy production from natural gas to coal, is probably the primary reason for this result.

With the recent passage of the 1990 Clean Air Act Amendments, allowances (limitations) on total utility SO_2 emissions are phased in over two time periods. In the initial time period 1995-1999 (Phase I), utilities with units having emission rates exceeding 2.5 lbs SO_2 per million BTU of fuel must reduce total emissions. None of the Nebraska coal units, since they use low sulfur coal, are affected by Phase I. In Phase II, all remaining coal plants and utilities are affected. Allowances are set on a plant-by-plant basis based on actual SO_2 emissions with a maximum of 1.2 lbs SO_2 per million BTU of fuel consumed during the 1985-1987 period. Plants that emit on an average below 0.6 lbs SO_2 per million BTU of fuel receive a 20% bonus because they are already cleaner than the most stringent standard for new coal units.

The DSM options reduce NO_x emissions from the Supply-Side-Only Base case while reducing total costs 1.3%. The Gas Fuel Price + 30% case reduces NO_x emissions by 1.6% at an increased cost of 0.5% over the Integrated Base case. The range in cumulative NO_x (nitrogen oxide) emissions is shown by the five selected cases on Figure 5.2.4-2. The Supply-Side-Only case has the highest NO_x emissions but is essentially equal to the Integrated Base case, only 0.05% higher.

The most dramatic change in NO_x emissions occurs with the Integrated Clean Coal case. Emissions are reduced 16.8% while costs increase 6.0%. This reduction in NO_x emissions is primarily due to the lower NO_x emission rate of the Integrated Gasification Combined Cycle units.

The range in cumulative CO_2 (carbon dioxide) emissions for the planning period is shown by the five selected cases on Figure 5.2.4-3. There is very little difference in CO_2 emissions. The largest change is a reduction of 1.0% for the Integrated Clean Coal case, at a cost increase of 6.0%. Although costs

FIGURE 5.2.4-1

CUMULATIVE SO2 EMISSIONS 1990-2019

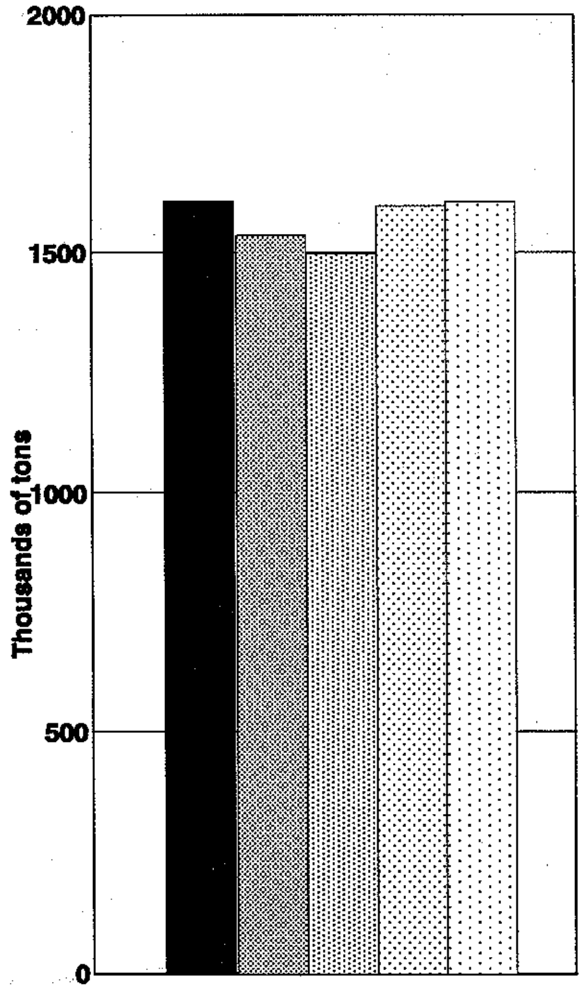


FIGURE 5.2.4-2

CUMULATIVE NOX EMISSIONS 1990-2019

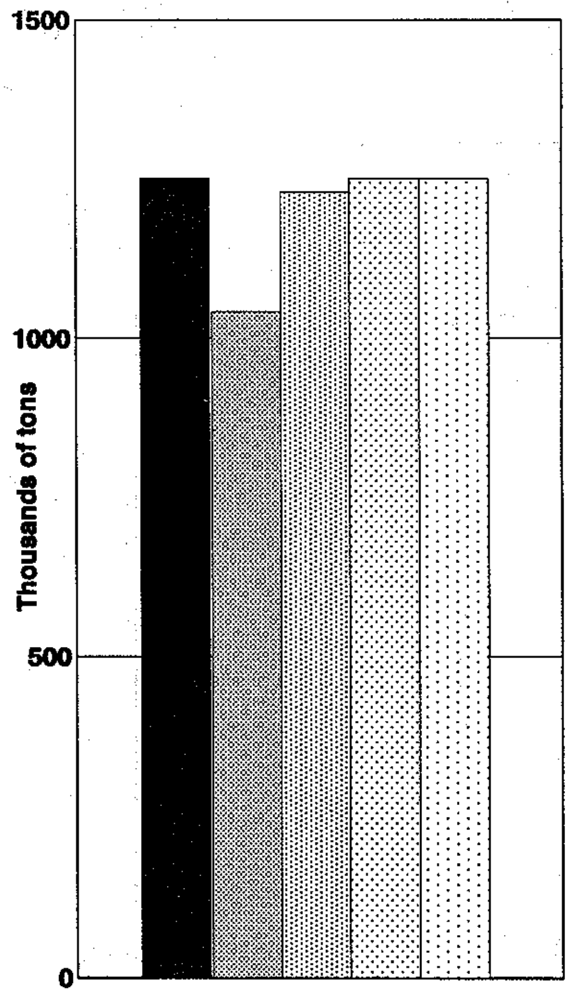
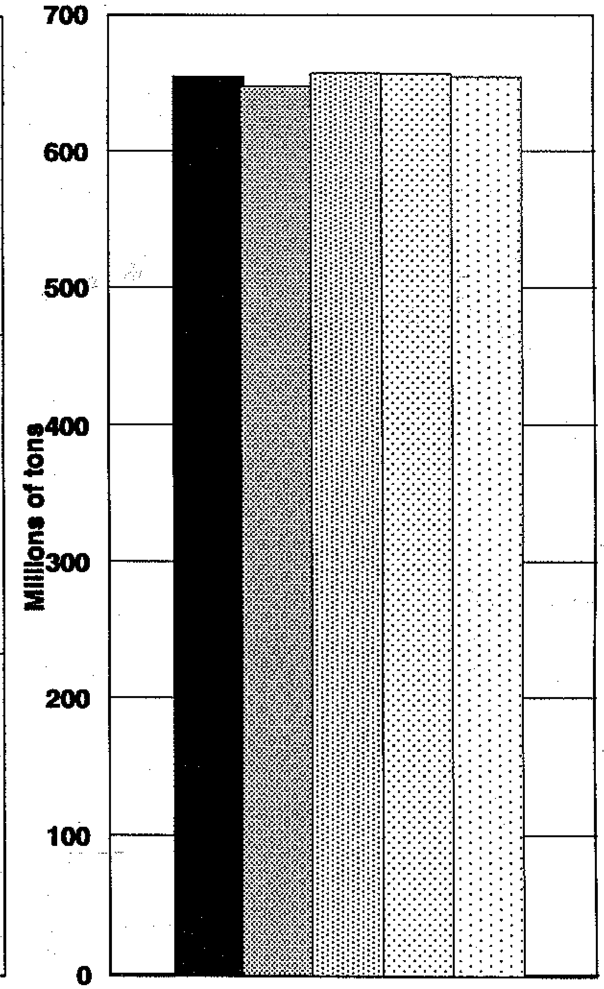


FIGURE 5.2.4-3

CUMULATIVE CO2 EMISSIONS 1990-2019



INTEGR BASE CASE
INTEGR CLEAN COAL
INTEGR GAS +30%
SUPPLY BASE CASE
INTEGR HR 4805 CARBON TAX

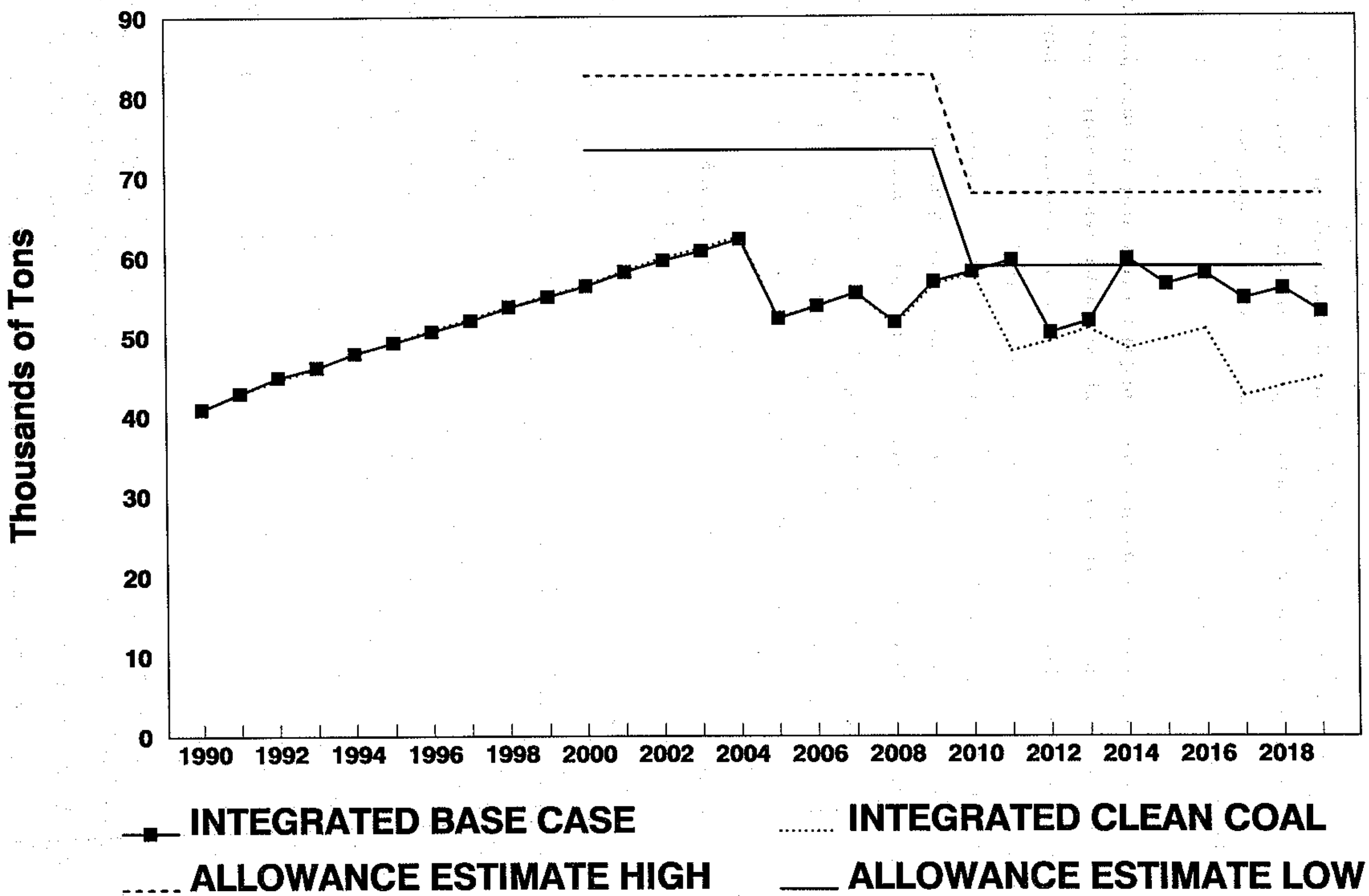
increase 13.6% for the HR 4805 Carbon Tax case, CO_2 emissions do not change. The DSM options reduce CO_2 emissions 0.4% while reducing total costs 1.3% from the Supply-Side-Only Base case.

A high and low estimate for years 2000 to 2009 for the total allowances for Nebraska utilities are shown as the horizontal lines at 82,600 and 73,400 tons per year of SO_2 on Figure 5.2.4-4. In 2010 these levels reduce. These ranges are only estimates because the regulations for the law have not been written and, therefore, the impact of the Act is not totally clear. The annual SO_2 emissions of the Integrated Base case and the Integrated Clean Coal case are also shown. Total annual emissions from all Nebraska owned coal units, including new plants in the future, cannot exceed the allowance limit. Unused allowances from a year can be banked for future use. Since SO_2 emissions do not exceed the high limit in any year and sufficient allowances can be banked for the low limit, Nebraska utilities as a whole apparently do not face the prospect of having to purchase allowances from other utilities or retrofit scrubbers onto existing coal units that already burn low sulfur coal in order to be in compliance with the law.

5.2.5 Transmission Implications of the Sensitivity Cases

Because the resource expansion plans do not vary drastically during the reporting period for the various sensitivity cases, the transmission expansion differences also are not great. For the two cases with two 600 MW coal units added after Nebraska City #2, the result would be two units located at one of the two future sites, or a single unit located at each. As mentioned in Section 5.1.5, the transmission additions for a single unit at either of the two future sites are shown on the transmission map in Appendix E. Cost estimates for these facilities are: about $27,000,000 for the first unit at the Lincoln site, and about $121,000,000 for the first unit at the central Nebraska site (all 1990 dollars). The cost estimates for second units at these sites were prepared as follows: about $15,400,000 for a second unit at Lincoln, and about $102,400,000 for a second unit in central Nebraska (all in 1990 dollars).

FIGURE 5.2.4-4
ANNUAL SO2 EMISSIONS 1990-2019



In the Low Load case (having only one 600 MW coal unit added), the only significant transmission additions are the facilities associated with Nebraska City #2.

5.3 Other Results and Issues

Nebraska utilities, like other utilities across the nation, are involved in a very dynamic industry. Decision making can entail major risk-taking because of the sizeable facilities, large capital costs, many people, and varied political interests involved. This section presents some of the primary issues monitored by the NPA utilities in their planning activities.

5.3.1 Oil-Price Shock

The prospects for a near-term oil price shock seemed to diminish with the quick end to the Persian Gulf War early in 1991. Long term projections for stable supplies and prices rising at 2 percentage points above inflation, as used in this Study, continue to appear appropriate.

5.3.2 Environmental Issues

There are many environmental issues to be addressed by the United States and the electric utilities in the next several years. The likely result of this will be more regulation than already exists as was previously discussed in Section 4.5. Electric utilities will continue to make significant investment in research on the environmental effects of all aspects of the industry. By doing this it is hoped that the regulations that are put in place would indeed be warranted and would be structured to obtain the appropriate goals. This section is an expansion of and addition to some of the issues previously described in Section 4.5.3.2.

There is substantial work in progress to complete the regulations required to implement the Clean Air Act Amendments of 1990. These regulations will have a significant effect on how the law is implemented. They will also affect how allowances and allowance trading are handled. The allowance trading issue can be a significant issue for the country, for MAPP, and for Nebraska utilities as well. Utilities are currently efficient at buying and selling capacity and energy to optimize economies for their systems. The allowance trading adds a whole new dimension to these transactions and will also need to be efficiently developed.

Current legislative proposals suggest that taxing of carbon in fuels is a possibility. This Study indicates that this tax may not be an effective way of reducing CO_2 emissions, at least for the state of Nebraska, because the tax did not result in a different expansion plan. However, it would very significantly increase the cost of electric service for the customers within the state. The tax as proposed is levied against the utility, collected from the consumer, and paid to the federal government. It would be important that the tax income be used to offset CO_2 emissions if environmental improvement is to be realized. For example, the federal government could take the tax money and invest in research in CO_2 control, plant trees, etc.

NO_x emissions standards are expected to be further defined and could affect electric utilities and their costs.

Other emissions, certain refrigerants, hazardous or toxic chemicals, solid waste, sludge, and thermal effects could become more of an environmental issue in the future. If further studies result in additional standards, such standards could materially affect electric generation cost and availability.

With the current drought situation in the Midwest, water use and water rights are issues. The competition for the limited water resource is expected to increase in intensity.

5.3.3 Capacity Transactions

Certain additional subsets of the resource options studied are indeed possible. For example, resource needs and surpluses around the region, but outside the state, will contribute to some buying and selling of resources other than those modeled. Specifically capacity transactions during the

1990's and some independent power producer arrangements are expected. Not only may it be that surpluses are sold outside the state but the surpluses of others may be purchased by Nebraska utilities. A consideration for not studying long-term purchases from outside the state, is that tax-exempt financing allows Nebraska utilities to construct facilities as or more economically than those other utilities. However, it is not anticipated that these considerations on capacity transactions will materially affect the primary findings of this Study.

5.3.4 National Energy Strategy

In July, 1989, President Bush directed the Department of Energy (DOE) to begin development of a new National Energy Strategy (NES). The President said the Strategy was to be "built on a national consensus and to be responsive to new knowledge and new ideas, and to global, environmental, and international changes". A final report to the President was not available as of this writing.

The following is a summary of items expected to be recommended by the DOE in the NES that will have an impact on power supply.

Energy Conservation and Efficiency

- energy conservation standards for electric lights
- loans to implement energy conservation measures at government agencies
- remove taxes on rebates by utilities to customers who install high efficiency lighting and appliances

Nuclear Power

- consolidate construction and operating licensing into a single procedure
- accelerate the introduction of standard designs for nuclear power plants

Power Marketing Administrations

- changes in debt repayment structure for federal hydro power facilities

Renewable Energy

- tax credits for energy production by solar thermal, photovoltaics, wind and biomass technologies
- remove power production limitations from alternative power plants

Public Utility Holding Company Act

- allow utilities and non-utility organizations to use holding company structure to build and finance Independent Power Producers

Transportation

- mandate use of alternative (non-petroleum based) fuels in a percent of vehicles produced after 1994

Hydroelectric Regulation

- authorize FERC to coordinate a combined federal and state review process for hydro project applications and relicensing

Fuel Regulation

- replace existing FERC regulatory authority over oil pipelines
- allow import and export of natural gas without prior Federal government approval
- give FERC sole jurisdiction over environmental impact statements for gas pipelines

It is too early to predict what portions of the National Energy Strategy will be implemented through legislation and/or regulatory changes, and what impact it will have on future power supply options within the State of Nebraska.

5.3.5 Hydro Relicensing

In June of 1984, Nebraska Public Power District and Central Nebraska Public Power & Irrigation District filed new license applications with the Federal Energy Regulatory Commission (FERC) for four hydro plants. In December of 1984, FERC found the applications deficient because they did not adequately address the endangered species issues of the Platte River. Since the Districts' licenses expired in 1987, the FERC has issued annual licenses for the projects. In February, 1990, FERC issued an order imposing interim conditions on NPPD's annual license including instream flows for wildlife, monitoring programs, and the construction of eight artificial nesting sites for endangered and threatened birds. FERC subsequently stayed the minimum flow requirement. In May of 1990, NPPD and Central filed joint responses to the deficiencies identified by FERC on the original applications.

These projects were designed to provide irrigation water, hydropower, and recreation. The projects presently provide water to approximately 500,000 acres of farmland, provide 118 MW of hydropower, and also support recreation at numerous reservoirs and canals, provide wildlife and fisheries habitat, flood control, and groundwater recharge. The water flowing through these systems also provides cooling water to 1385 MW of electric steam generating capability (1278 MW Gerald Gentleman Station and 107 MW Canaday). Specific hydropower facilities of 118 MW capability include NPPD's North Platte Hydro (24 MW) and Central's Kingsley (38 MW), Jeffrey (18 MW) and Johnson I & II (38 MW).

During the late 1930's, when these projects were built, and the 1940's, when they were licensed, the wildlife interests in the Platte River were not high on the agenda of items considered important. Over the past 50 plus years, society's views have changed and FERC's regulatory process now takes these additional public benefits into consideration.

As a result, numerous agencies, interest groups, and states have become involved in the FERC relicensing process and numerous lawsuits challenging actions of FERC have been filed.

The Districts continue to search for a means to provide a mediated settlement of Nebraska's interests. FERC is preparing an Environmental Impact Statement for the Projects of which the draft is scheduled to be issued during the Fall of 1991 and a final in the Spring of 1992. Subsequently, FERC will issue new licenses for operating the projects which will attempt to balance the limited resources of the Platte River while hopefully protecting the irrigation and hydroelectric benefits as much as possible.

5.3.6 Open Access Transmission

Transmission access and use of the bulk power transmission system will most likely be a significant issue facing transmission system owners, producers and providers of electricity in the 1990's. Each has a substantial stake in the outcome of the debate.

The major issues involved in transmission access policy are:

- voluntary wheeling versus regulatory imposed access
- maintaining the reliability and integrity of the interconnected transmission system into the future
- pricing for access
- integrated planning, funding and operation of the transmission system with expanded access
- criteria for obtaining access

The impact on Nebraska will not be clear until many of the foregoing issues are resolved.

5.3.7 Nuclear Waste

5.3.7.1 Low-Level Radioactive Waste

The federal Low-Level Radioactive Waste Policy Act (Public Law 96-573) and amendments of 1985 (Public Law 99-240) require that each state is responsible for the disposal of low-level radioactive waste (LLRW) generated within its borders. The Act further requires that states and/or compacts must develop disposal capability to manage their wastes by January 1, 1993. To ensure that the 1993 deadline is met, the Act imposes surcharges and other significant penalties if progress milestones are not met.

In order to meet this responsibility, the states of Arkansas, Kansas, Louisiana, Nebraska, and Oklahoma have enacted the Central Interstate Low-Level Radioactive Waste Compact. The Compact is proceeding to site, construct, and develop a regional LLRW disposal facility by the January 1, 1993, deadline. The compact status as of January, 1990, is shown in Figure 5.3.7.1-1.

The 1989 assessment of state-by-state radioactive waste shipments shows that the volume of waste from the two Nebraska nuclear plants is about 16,700 cubic feet. This compares with about 21,000 cubic feet generated and shipped in 1986. The decrease demonstrates the significant effort being made to reduce waste volume.

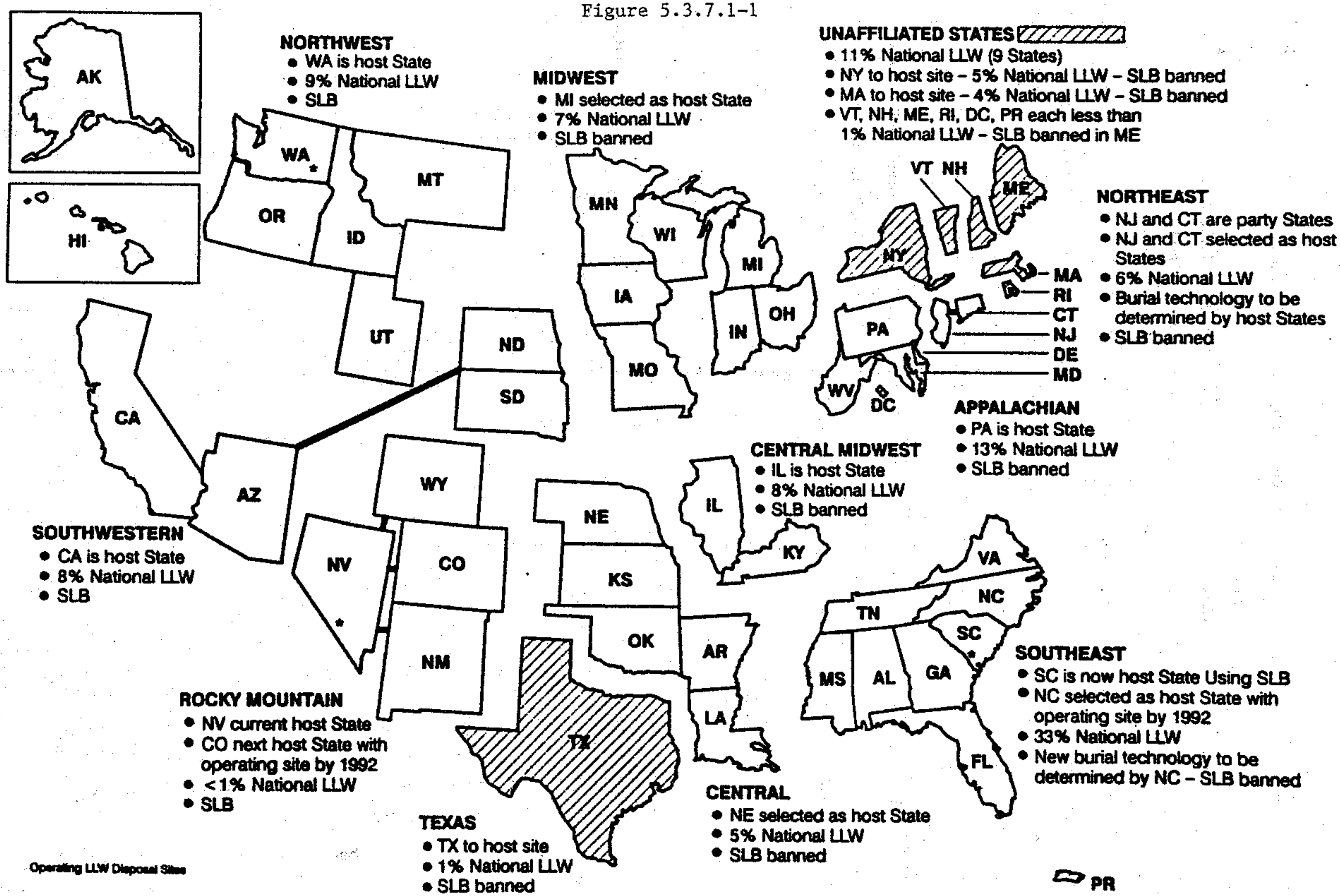
5.3.7.2 High-Level Radioactive Waste

The federal government has the responsibility for disposal of high-level radioactive waste. On November 19, 1989, the Secretary of Energy sent a report to Congress announcing a rescheduling and restructuring of DOE's high level radioactive waste program. The report states that the repository opening is further delayed from 2003 to 2010 but that the 1998 commitment to begin receiving spent fuel will be met by way of a Monitored Retrievable Storage (MRS) facility. To fund the disposal project development, utilities

LOW-LEVEL RADIOACTIVE WASTE COMPACT STATUS

JANUARY 1990

Figure 5.3.7.1-1



Note: National LLW volume for 1988 = 1.4 million cubic feet.
SLB = shallow land burial

Source: State, Local and Indian Tribe Programs
Office of Governmental and
Public Affairs, NRC

pay a fee to the federal government of one mill per kilowatt-hour. The sufficiency of this fee is also a topic for debate.

Early in 1990, the General Accounting Office (GAO) released a report titled, "Nuclear Waste - Changes Needed in DOE User-Fee Assessments to Avoid Funding Shortfall." The report states that, "Without a fee increase the civilian waste program may already be underfunded by 2.4 billion dollars." The report recommends that Congress amend the Nuclear Waste Policy Act to authorize the Secretary of Energy to adjust the Nuclear Waste Disposal fee on the basis of an inflation index.

The Edison Electric Institute has reviewed the GAO report and concluded that GAO statements that the repository program will experience a 2.4 billion dollar shortfall 85 years from now are unsupported by facts.

According to EEI figures, there is a 2.5 billion dollar surplus in the Nuclear Waste Fund now; the program collects over 500 million dollars from electric utilities each year while current spending levels are 300 million dollars per year. Additionally, the government has not paid its fair share for disposal of military waste to be stored in the repository. Finally, the alleged shortfall of 2.4 billion in 85 years is for a 25 billion dollar program. The uncertainty inherent in such calculations make the 2.4 billion dollars figure highly unreliable. EEI concludes that no increase in the present Nuclear Waste Fund fee of one mill per kilowatt-hour is justified.

5.4 Comparison to the Previous Study

In the last five years, peak demand for electricity grew more slowly than projected in the 1986 Study. Based on the 1986 Study, the 1990 summer peak demand for the State was projected to be 4,828 MW as shown in Table 5.4-1. Actual peak demand for the summer of 1990 was 4,680 MW. The forecasted 20-year load growth rate is lowered from 2.1% in the 1986 Study to 1.7% per year in the 1991 Study. Consequently, the first year of capacity need is delayed from 1998 to 2000. As a result of the lower growth rate, coupled with the assumed extension of operation at Cooper, Canaday and North Omaha #1 and #2

Table 5.4-1
Comparison to the Previous 1986 Study

Statewide Quantity (Units)	1986 Study	1991 Study
10-yr Peak Load Growth Rate (% per yr)		
Base	2.24	1.84
High	2.74	2.45
Low	1.74	1.06
20-yr Peak Load Growth Rate (% per yr)		
Base	2.08	1.73
High	2.60	2.36
Low	1.57	0.99
Year 1990 Summer Peak Load (MW)	4828	4620 (Proj.) 4680 (Act.)
Year 2008 Summer Peak Load (MW)	6920	6298
Capacity Need Year	1998	2000
First Unit Type	650 MW Neb City 2	DSM, CT's
Base Expansion Plans Through 2008 (MW)		
Efficient Heat Pump	---	59 (1993)
Interruptible Load & Leased Generation	---	138 (1996)
Commercial Lighting	---	95 (1996)
Combustion Turbines	480 (02,08)	320 (02,03)
Nebraska City #2	650 (1998)	600 (2005)
600 MW Coal	1800 (03,06,08)	600 (2008)
Fuel Cells	320 (2008)	---
TOTAL	3250	1812*
20-yr Fuel Cost Escalation (% per yr)		
Coal	5.68	5.00
Natural Gas	7.49	6.84
Oil	7.73	6.84
Year 2000 Fuel Price in 1985$/MMBtu		
Coal	1.45	0.59
Natural Gas	5.54	2.12
Oil	9.06	3.77

* Lowered resource requirements projected in the 1991 Study are due to assumed lower load growth forecast coupled with the assumed extension of operation at Cooper, Canaday, and North Omaha #1 and #2 units.

units, the total resource need through 2008 is reduced from 3,250 MW to 1,812 MW.

Utilities and their customers in Nebraska have been working together in the development and implementation of selected demand-side options. These options include high efficiency air conditioners and heat pumps, improved building insulation, efficient lighting and load control of air conditioners and irrigation. Through these activities, the utilities in Nebraska are able to reduce peak demand in the summer and build loads in the winter.

Four demand-side management options totaling 292 MW are selected in the Integrated Base Resource Plan in the 1991 Study: efficient heat pump, interruptible load, leased generation, and efficient commercial lighting programs. In the previous Study, demand-side options were studied only as sensitivity scenarios. The first supply-side resource selected is combustion turbine capacity rather than a baseload coal unit at Nebraska City as projected in the 1986 Study.

Society, as well as electric utilities, is increasingly concerned about environmental issues. This Study attempts to assess the environmental impacts of the 1990 Clean Air Act Amendments as well as other potential legislative measures as they may affect electric generation and future electric utility plans in Nebraska.

Coal, natural gas, and fuel oil for electric generation have remained in good supply. The cost of fuel actually decreased over the last five years. The low cost of fuel is forecasted to continue in the new Study. The rate of cost escalation is also projected to be lower than in the previous study.

SECTION 6

SUMMARY AND CONCLUSIONS

6.0 Summary and Conclusions

The purpose of this chapter is to summarize the report and collect conclusions resulting from the Study analysis. More detail concerning specific discussion points can be found elsewhere in the report.

It is important to keep in mind that with an analysis involving more than one utility, the results will have varying impacts on the individual utilities. The financial benefits of joint construction, demand-side management, or conservation programs resulting from a study of this nature may not be available to all the individual utilities and their customers to the same degree. Because of this, individual utilities may not be able to economically justify participation in some joint projects and further, some demand-side options may appear to be beneficial for the state but may not be beneficial for some individual utilities and their customers.

6.1 Fulfillment of the Purpose and Objectives

The purpose and objectives of the Study, as outlined in Chapter 2, are in response to the needs of the Nebraska Power Review Board (Nebraska Statute 70-1025) and of the utilities themselves. An Integrated Base Resource Plan is developed which considers the costs in the three principal areas: the utility, the customers, and the environment. In the areas of DSM and environmental impacts, this Total Cost evaluation comprises the most comprehensive Study done to date by the NPA.

It is anticipated that this state-of-the-art resource and transmission Study is not only sufficient for the needs of the Nebraska Power Review Board but will serve in the years to come as a sound and useful document by which Nebraska utilities can continue to plan for the electrical needs of their customers. In particular, the sensitivity runs should provide useful information to meet the need for flexibility in responding to those changing customer needs.

Rather than just studying and using resource options, Nebraska utilities participate in their research and development. For example, most NPA utilities participate in the management and funding of Electric Power Research Institute (EPRI). Of EPRI's $267 million annual budget, $77 million (29%) is dedicated to environmental activities and $36 million (14%) to DSM activities, both of which were given significant attention in this Study.

6.2 Historical Load Growth and Forecasted Load Growth

The load forecast can be considered as the primary input to a resource planning Study. Load growth in Nebraska slowed during the early 1980's and began to pick up in the latter years for an annual growth rate over the decade of 1.2% per year as shown in Table 4.1.2-3. Part of the reason for this slowing in growth has been due to the extensive development of load control for irrigation and other loads and significant conservation on the part of the customers. Load forecasts have been reduced to account for these trends. Table 5.4-1 shows that the forecasted growth rates have been reduced from 2.1% per year in the 1986 Study to the current rate of 1.7% per year. This revised forecast includes the continuation of existing DSM programs and is shown as the increasing dashed line in Figure 6.2-1. This reduction in growth rate has resulted in a lowered need for new resources.

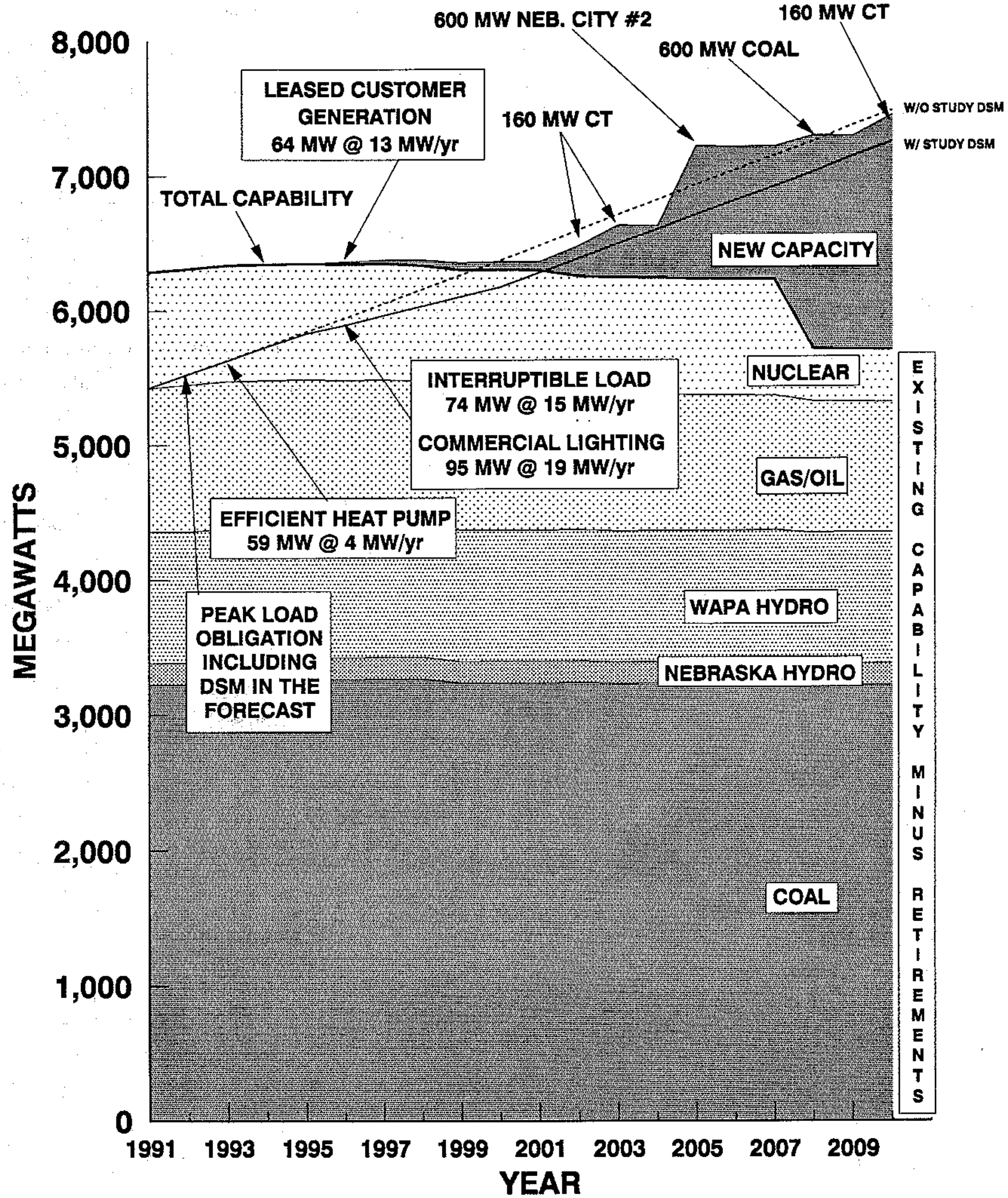
6.3 Integrated Base Resource Plan

The results in Section 5.1.1 showed that the expected need for resource additions is created 76% by increased load obligations and 24% by generating capacity retirements over the next twenty years. The major drop in existing capability shown in Figure 6.2-1 occurs in 2008 with the anticipated retirement of the Fort Calhoun Nuclear Station. The existing resources are shown by fuel type.

The new resources expected to meet the above needs are listed in Table 5.1.1-1 and depicted in Figure 6.2-1. The load-side study DSM resources lower the load obligation line and the capacity increases (DSM leased generation and supply-side resources) maintain the Nebraska capability line above the reduced

FIGURE 6.2-1

INTEGRATED BASE CASE LOAD AND CAPABILITY



obligation line. Note that three DSM programs are phased in with equal annual increments over a 5-year period beginning in 1996. The fourth DSM program, efficient heat pumps, is phased in over a 15-year period beginning in 1993.

Surplus existing supply-side resources meet 25% of the future needs, future supply-side resources meet 64%, and study DSM resources meet 11% as shown in Table 5.1.1-4. Twenty years from now the supply-side capacity is expected to be made up of approximately one-fourth "new" capacity and three-fourths existing capacity as shown in Figure 6.2-1. Coal capacity will still be predominant, increasing to nearly 60% of the total. For example, a new coal unit is very likely needed in conjunction with the retirement of Fort Calhoun Nuclear Station, currently estimated for 2008.

Lead times required to design, permit, and construct combustion turbines are approximately three years and are eight years for a second coal-fired unit at Nebraska City. The lead time required for a first coal unit at a new site could be nine years or more. DSM options typically have a short lead time of 1-2 years to initiate a customer program but a long lead time of 5-15 years to reach maximum participation levels, i.e., reach full effect. Based on these timing requirements, individual utilities are in the process of making resource planning decisions and can use the information gathered and findings of this Study.

The resource planning results of this Study are in good agreement with the long-term utility options currently being evaluated by individual Nebraska utilities, after allowing for the qualifications mentioned in Section 6.0. One change from the base plan in the 1986 Study, wherein Nebraska City Unit #2 was selected as the first resource to be added, is the selection in this Study to install 292 MW of DSM resources and 320 MW of combustion turbines prior to Nebraska City Unit #2.

6.4 Sensitivity Studies

Based on the discussion in Section 5.2.2 some summary comments and conclusions can be derived from the sensitivity cases. Specific environmental findings are given in Section 6.5. Much of the discussion in this section pertains to the sensitivity cases that were given integrated resource options to choose from.

In all the integrated cases, some DSM options were selected. In all the sensitivities, efficient residential heat pump and commercial lighting programs are selected. The industrial interruptible and leased generation programs are selected in all cases except for the Low Load Forecast. The air conditioner SCRAM program is selected in only one case, the Clean Coal case. From these results, it can be concluded that some additional DSM resources are economical based on total cost. This conclusion coincides with the current activity by individual Nebraska utilities in determining beneficial programs for their particular situation. Further discussion of DSM sensitivities is found in Section 6.6.

Generally, combustion turbines are selected next after the DSM options. This indicates the state needs peaking capacity. The only cases that do not select combustion turbines before the baseload unit are the Low Load Forecast, the CT +39% Capital Cost case, and the High Gas Cost case. These cases meet load growth with DSM until the Nebraska City #2 unit is installed in 2008 or 2002. In all other cases, 160-800 MW of combustion turbines are selected. Thus the cost and availability of combustion turbines need to be monitored.

Nebraska City Unit #2 is installed between 2001 and 2008 in this Study. The earliest date is with the High Load Forecast and the latest date is in two sensitivities; the Low Load Forecast and the 12 Percent Discount Rate cases. Thus the construction lead time for Nebraska City Unit #2 needs to be monitored as well.

In the High Gas Cost case, baseload coal capacity is installed earlier and includes one more unit, thereby displacing some gas CT's. Thus one of the key issues to examine is natural gas cost and, again, lead times required for Nebraska City Unit #2. If, however, the demand-side resources selected for this sensitivity case are not in place on time, then the supply-side-only run indicates that combustion turbine capacity would be required before Nebraska City Unit #2.

Other price sensitivities do result in cost changes but do not result in significant changes in resource mix through 2010. That is, independent increases in coal cost, combustion turbine capital cost, or coal unit capital cost do not change the resource plan. However, the significant change to the High Coal Cost does result in a $955 million increase which will be reflected in the cost of electricity throughout the planning period.

The increase in gas cost has a greater effect on the expansion plan than does the coal cost increase, but does not have as large an effect on the total cost, estimated at $122 million.

6.5 Environmental

One significant environmental conclusion is the size of the share of electricity cost dedicated to environmental concerns. Figures 5.1.2-2 and 5.1.2-3 show that for future coal plants operating at a typical 60% capacity factor, more than 20% of the costs are attributable to protection of the environment. In all of the cases, the estimated effect of the 1990 Clean Air Act Amendments was factored in.

The HR 4805 Carbon Tax case indicated that a high tax of up to $15/ton has the biggest effect on cost of all the sensitivities run (13.7%). However, this case has the same expansion through 2010 as the Integrated Base Resource Plan. That is, the tax results in an increased electricity cost but yields no direct environmental benefit.

The Clean Coal case has about half the increase in cost as does the HR 4805 Carbon Tax case and has the lowest CO_2 emissions. However, in all cases CO_2 emissions do not vary as significantly as do SO_2 and NO_x.

Because Nebraska City #2 will have lower emission levels than the existing units, emissions from existing units will be reduced as generation is displaced. Advancing Nebraska City Unit #2 particularly reduces SO_2 and NO_x emissions with only minor effect on CO_2.

The DSM options selected have little effect on emission totals.

Based on current interpretation of the 1990 Clean Air Act Amendments, Nebraska utilities as a group will be able to meet these new standards as shown in Figure 5.2.4-4. Individual utilities may, however, have to take some actions to comply. The effects of the law are being evaluated by each individual utility.

6.6 Demand-Side Management

The primary DSM conclusion is that the DSM resources selected in the Integrated Base Resource Plan eliminate the need for one 160 MW combustion turbine and provide one-year delays each for two 160 MW CT's and the 600 MW Nebraska City Unit #2 coal unit (see Table 5.1.1-1). In so doing, the integration of the DSM resources saves, in the total cost calculation, $299 million (1990$ P.V.) over 30 years (see Table 5.1.1-2).

As discussed in Section 6.4, DSM resources were selected in all the integrated cases. Different levels of customer participation in DSM programs were assumed as a further sensitivity on the demand-side management options. At all participation levels, DSM options were selected. However, the total cost benefit from the demand-side option does change significantly. In these cases, as well as most of the DSM cases, the air conditioner SCRAM was not selected as an option.

Generally the DSM options selected for the state in these integrated cases provided benefits to all parties over the planning period. If the DSM identified in the Integrated Base Resource Plan is implemented, the system load factor would improve from 51.3% to 52.1% in 2004. One reason that the change is small is that the heat pump program adds energy while the commercial lighting program reduces energy requirements.

This Study does demonstrate that conclusions are not always as obvious as one would think. This condition particularly applies to the air conditioner SCRAM option which was not picked in the vast majority of the integrated plan sensitivity cases. It would normally appear that with Nebraska needing peaking capacity first, air conditioner SCRAM would have been selected more frequently. Apparently the amount of peak shaving DSM options needed by the state is first met by the industrial interruptible and leased generation options and the more costly air conditioner SCRAM option was not needed.

6.7 Transmission Findings

Considering the Study results for the twenty-year reporting period, the transmission facility additions necessitated by the possible resource expansion plans (for the base case and the sensitivity cases) are not major impacts --- either in dollars or in miles of transmission line.

The cost of base case transmission additions are $75,000,000 to $170,000,000 (1990 dollars). This corresponds to a range of 120 to 420 miles of line. The sensitivity cases with the greatest transmission requirements have transmission expansion costs ranging from $90,000,000 to $270,000,000 (1990 dollars), which corresponds to 155 to 690 miles of line.

As pointed out in Section 4.4, the costs for expanding the transmission network are small relative to the resource expansion expense. Because the number of miles of transmission lines that might be added are not large, the transmission facilities should not have adverse effects on Nebraska's communities and farms.

APPENDIX A

NEBRASKA STATUTE

APPENDIX A

NEBRASKA STATUTE 70-1025

(Relating to the Nebraska Power Review Board and the Long-Range Power Supply Plan)

70-1025. **Power supply plan; contents; annual report.** (1) The representative organization shall file with the board a coordinated long-range power supply plan containing the following information:

(a) The identification of all electric generation plants operating or authorized for construction within the state that have a rated capacity of at least twenty-five thousand kilowatts;

(b) The identification of all transmission lines located or authorized for construction within the state that have a rated capacity of at least two hundred thirty kilovolts; and

(c) The identification of all additional planned electric generation and transmission requirements needed to serve estimated power supply demands within the state for a period of twenty years.

(2) Beginning in 1986, the representative organization shall file with the board the coordinated long-range power supply plan specified in subsection (1) of this section, and the board shall determine the date on which such report is to be filed, except that such report shall not be required to be filed more often than biennially.

(3) An annual load and capability report shall be filed with the board by the representative organization. The report shall include statewide utility load forecasts and the resources available to satisfy the loads over a twenty-year period. The annual load and capability report shall be filed on dates specified by the board.

Source: Laws 1981, LB 302, § 3; Laws 1986, LB 948, § 1.

APPENDIX B

LOAD AND CAPABILITY

APPENDIX B

LOAD & CAPABILITY FOR THE BASE FORECAST

(BEFORE THE ADDITION OF DEMAND/SUPPLY ALTERNATIVES)

Base Load Forecast:	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	30 yr Growth Rate
OPPD	1642	1676	1707	1740	1773	1807	1843	1880	1917	1956	1995	2034	2073	2113	2152	2193	2234	2275	2317	2359	2402	2445	2489	2533	2578	2623	2668	2714	2760	2807	1.87%
LES	527	545	562	580	596	611	625	641	656	669	686	706	724	743	763	782	798	812	826	844	859	872	886	899	907	913	925	937	949	961	2.09%
NPPD	1708	1738	1767	1795	1826	1857	1884	1914	1945	1973	1999	2025	2053	2078	2102	2131	2155	2178	2204	2234	2257	2283	2308	2334	2359	2384	2409	2434	2459	2485	1.30%
Tri-State	260	263	264	265	266	267	268	270	271	273	274	275	277	279	280	281	282	283	285	286	287	288	289	290	291	293	294	295	296	297	0.46%
NMPP	483	492	502	512	522	531	541	551	561	572	582	592	602	613	623	634	645	656	666	677	689	700	711	722	734	745	757	769	780	792	1.72%
Subtotal	4620	4714	4802	4892	4983	5073	5161	5256	5350	5443	5536	5632	5729	5826	5920	6021	6114	6204	6298	6400	6494	6588	6683	6778	6869	6958	7053	7149	7244	7342	1.61%
Firm Sales:																															
OPPD - Wholesale	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	12	12	12	12	12	12	
OPPD - Muni	0	0	0	0	0	0	0	0	0	0	0	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Subtotal	9	9	9	9	9	9	9	10	10	10	10	11	11	12	12	12	13	13	13	13	13	13	13	13	14	14	14	14	14	14	
Firm Purchases:																															
OPPD - WAPA Total	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	
LES - WAPA Firm	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	
LES - WAPA Peaking	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	
NPPD - WAPA Firm	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	
NPPD - WAPA Peaking	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	
Tri-State	260	263	264	265	266	267	268	270	271	273	274	275	277	279	280	281	282	283	285	286	287	288	289	290	291	293	294	295	296	297	
NMPP	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	
Subtotal	1021	1024	1025	1026	1027	1028	1029	1031	1032	1034	1035	1036	1038	1040	1041	1042	1043	1044	1046	1047	1048	1049	1050	1051	1052	1054	1055	1056	1057	1058	
Net Load	3608	3699	3786	3875	3965	4054	4141	4235	4328	4419	4511	4607	4702	4798	4891	4991	5084	5173	5265	5366	5459	5552	5648	5740	5831	5918	6012	6107	6201	6298	

APPENDIX B

Existing Resources:	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jones Street	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
Sarpy County	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Tecumseh	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
North Omaha - Coal	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	399	399	399	319	319	239
North Omaha Topping	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	40	40	40	31	31	31
North Omaha Replacem	89	104	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	116	116	116	102	102	79
Fort Calhoun	476	476	476	476	476	476	476	476	476	476	476	476	476	476	476	476	476	476	0	0	0	0	0	0	0	0	0	0	0	0
Nebraska City #1	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585
Rokeby	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
J Street	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
Laramie River	182	182	182	207	212	217	217	217	217	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182
Cooper	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	0	0	0	0	0	0
Gerald Gentlemen	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278
Sheldon	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Canaday	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107
Hallam	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Hebron	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
McCook	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Schuyler	8	8	8	8	8	8	8	8	8	8	8	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD Small Diesels	38	38	38	38	38	38	34	34	34	34	34	34	34	34	29	29	29	29	29	29	29	20	20	20	20	20	20	7	7	7
NPPD Hydro	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Kingsley Hydro	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
CNPP Hydro	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Loup Hydro	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Fairbury 2&3	15	15	15	15	15	15	15	15	11	11	11	11	11	11	11	11	11	11	11	11	11	0	0	0	0	0	0	0	0	0
Grand Island 1-3 & CT	107	107	107	107	107	107	107	107	107	107	107	107	91	91	91	91	91	91	69	69	69	69	69	69	69	69	69	69	69	69
Hastings 1,4,5	58	58	58	58	58	58	58	58	58	58	58	58	43	43	43	43	43	43	43	43	43	43	21	21	21	21	21	21	21	21
Hastings Energy Center	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
NMPP Small Diesels	166	166	166	166	166	166	166	166	155	153	152	147	141	139	138	128	128	122	119	116	111	111	110	107	104	100	91	90	85	79
Fremont 6-8	120	120	120	120	120	120	120	120	120	120	120	120	120	109	109	109	109	109	87	87	87	87	87	87	87	87	87	87	87	87
Platte Generating Station	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
TOTAL RESOURCES	5095	5110	5135	5160	5165	5170	5166	5166	5151	5113	5113	5108	5063	5050	5044	5034	5032	5028	4504	4502	4497	4476	4453	4450	3983	3979	3970	3854	3848	3740
SURPLUS or DEFICIT	946	856	781	704	605	508	404	298	174	31	-75	-190	-344	-468	-581	-706	-815	-921	-1551	-1669	-1781	-1909	-2040	-2151	-2723	-2827	-2944	-3169	-3283	-3503
Change From Prev Year	n/a	90	75	77	99	97	104	108	122	143	106	115	154	124	113	125	109	106	630	118	112	128	131	111	572	104	117	225	114	220

APPENDIX B

Utility Specific L&R:	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPPD Resources	1868	1883	1907	1927	1927	1927	1927	1927	1927	1927	1927	1907	1907	1907	1907	1907	1907	1907	1431	1431	1431	1431	1431	1431	1356	1356	1356	1254	1254	1152
OPPD Net Load	1571	1605	1636	1669	1702	1736	1772	1810	1847	1886	1925	1965	2004	2045	2084	2125	2167	2208	2250	2292	2335	2378	2422	2466	2512	2557	2602	2648	2694	2741
Surplus or Deficit	61	37	26	8	-30	-69	-111	-155	-197	-242	-287	-353	-398	-445	-490	-537	-585	-632	-1157	-1205	-1254	-1304	-1354	-1405	-1533	-1585	-1636	-1791	-1844	-2000
NPPD Resources	2055	2055	2055	2055	2055	2055	2051	2051	2051	2051	2051	2051	2043	2043	2038	2038	2038	2038	2038	2038	2038	2029	2029	2029	1737	1737	1737	1724	1724	1724
NPPD Net Load	1242	1272	1301	1329	1360	1391	1418	1448	1479	1507	1533	1559	1587	1612	1636	1665	1689	1712	1738	1768	1791	1817	1842	1868	1893	1918	1943	1968	1993	2019
Surplus or Deficit	627	592	559	527	491	455	420	386	350	318	288	258	218	189	157	123	96	69	39	5	-22	-61	-89	-119	-440	-469	-497	-539	-568	-598
LES Resources	524	524	524	549	554	559	559	559	559	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	427	427	427	427	427	427
LES Net Load	418	436	453	471	487	502	516	532	547	560	577	597	615	634	654	673	689	703	717	735	750	763	777	790	798	804	816	828	840	852
Surplus or Deficit	43	23	3	7	-6	-18	-34	-53	-70	-120	-140	-163	-183	-205	-228	-250	-288	-284	-301	-321	-338	-353	-370	-384	-491	-498	-511	-525	-539	-553
Tri-State Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tri-State Net Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Surplus or Deficit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NMPP Resources	648	648	648	628	628	628	628	628	614	611	610	625	589	576	575	565	562	559	511	509	504	492	489	465	463	459	450	449	443	437
NMPP Net Load	377	386	396	406	416	425	435	445	455	466	476	486	496	507	517	528	539	550	560	571	583	594	605	616	628	639	651	663	674	686
Surplus or Deficit	215	205	193	162	150	140	128	117	90	75	63	66	19	-7	-20	-42	-58	-74	-133	-148	-167	-191	-227	-243	-259	-276	-298	-313	-332	-352
In-State Transfers:																														
NMPP to OPPD	0	0	0	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD to LES (Cooper)	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	0	0	0	0	0	0
NPPD to LES (GGS#1)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
NPPD to LES (GGS#2)	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
NPPD to LES (Sheldon)	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
LES to NMPP (Laramie)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

APPENDIX B

Calculation of Maximum Units Required:	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPACITY DEFICIT	0	0	0	0	0	0	0	0	0	0	75	190	344	468	581	706	815	921	1551	1669	1781	1909	2040	2151	2723	2827	2944	3169	3283	3503
Change	0	0	0	0	0	0	0	0	0	0	75	115	154	124	113	125	109	106	630	118	112	128	131	111	572	104	117	225	114	220
Pulverized Coal Units 600 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	2	1	1	1	1	1	1	1	1	1	1	1
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	3	3	3	4	4	4	5	5	5	6	6	6
Pulverized Coal Units 300 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	3	1	1	1	1	1	2	1	1	1	1	1
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	1	2	2	2	3	3	4	6	6	6	7	7	8	10	10	10	11	11	12
Pulverized Coal Units 250 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	3	1	1	1	1	1	3	1	1	1	1	1
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	1	2	2	3	3	4	4	7	7	8	8	9	9	11	12	12	13	14	15
Combustion Turbines 160 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	4	1	1	1	1	1	4	1	1	2	1	2
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	2	3	3	4	5	6	6	10	11	12	12	13	14	18	18	19	20	21	22
Combined Cycles 150 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	1	2	1	1	1	1	1	5	1	1	1	1	1	4	1	1	2	1	2
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	2	3	4	4	5	6	7	11	12	12	13	14	15	19	19	20	22	22	24
Fuel Cells 144 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	1	2	1	1	1	1	1	5	1	1	1	1	1	4	1	1	2	1	2
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	5	6	7	11	12	13	14	15	15	19	20	21	22	23	25
Integrated Coal Gasificati 500 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	2	1	1	1	1	1	2	1	1	1	1	1
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	1	1	1	2	2	2	2	4	4	4	4	5	5	6	6	6	7	7	8
Compressed Air Storage 110 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	1	1	6	2	2	2	2	2	6	1	2	3	2	2
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	2	4	5	6	7	8	9	15	16	17	18	19	20	25	26	27	29	30	32
Advanced Batteries 120 MW																														
Maximum Per Year	0	0	0	0	0	0	0	0	0	0	1	1	2	2	1	2	1	1	6	1	1	2	2	1	5	1	1	2	1	2
Maximum Cumulative	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	13	14	15	16	17	18	23	24	25	27	28	30

APPENDIX C

EXISTING GENERATING UNITS

APPENDIX C

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
LINCOLN ELECTRIC SYSTEM				
UNIT NAME	**UNIT** TYPE**	**FUEL** TYPE**	**YEAR OF COMMERCIAL OPERATION**	**SUMMER CAPACITY MW**
8th & J Street	CT	O/NG	1972	29.00
Rokeby	CT	O	1975	56.00
Laramie* Unit No. 1	F	C	1982	173.00
TOTAL				258.00

* Wheatland, Wyoming

****EXPLANATION OF UNIT AND FUEL TYPE**

UNIT TYPE	FUEL TYPE
H - Hydro	HS - Run of River
D - Diesel	NG - Natural Gas
N - Nuclear	O - Oil
CT - Combustion Turbine	C - Coal
F - Fossil	HR - Reservoir
	U - Uranium

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
NEBRASKA PUBLIC POWER DISTRICT				
UNIT NAME	UNIT** TYPE	FUEL** TYPE	YEAR OF COMMERCIAL OPERATION	SUMMER CAPACITY MW
Canaday Unit No. 1	F	O/NG	1958	107.00
Columbus-Monroe Unit No. 1	H	HR	1936	13.30
Columbus-Monroe Unit No. 2	H	HR	1936	13.30
Columbus-Monroe Unit No. 3	H	HR	1936	13.40
Cooper Unit No. 1	N	U	1974	778.00
David City Unit No. 1	D	O/NG	1960	1.30
David City Unit No. 2	D	O/NG	1949	0.80
David City Unit No. 3	D	O/NG	1955	0.90
David City Unit No. 4	D	O/NG	1966	1.80
Gentleman Unit No. 1	F	C	1979	630.00
Gentleman Unit No. 2	F	C	1982	648.00
Hallam Unit No. 1	CT	O	1973	40.00
Hebron Unit No. 1	CT	O	1973	39.00
Holdrege Unit No. 1	D	O	1938	0.50
Holdrege Unit No. 2	D	O	1952	1.00
Holdrege Unit No. 3	D	O	1945	0.50
Jeffrey Unit No. 1	H	HR	1940	9.00
Jeffrey Unit No. 2	H	HR	1940	9.00
Johnson I Unit No. 1	H	HR	1940	9.50
Johnson I Unit No. 2	H	HR	1940	9.50
Johnson II Unit No. 1	H	HR	1940	19.00
Kearney Unit No. 1	H	HR	1922	1.00
Kingsley Hydro Unit No. 1	H	HR	1985	38.00
Lyons Unit No. 1	D	O	1967	1.10

EXISTING GENERATING UNITS IN NEBRASKA
(Based on Ownership and/or Reporting Responsibility)

NEBRASKA PUBLIC POWER DISTRICT (Cont'd)

UNIT NAME	UNIT** TYPE	FUEL** TYPE	YEAR OF COMMERCIAL OPERATION	SUMMER CAPACITY MW
Madison Unit No. 1	D	O/NG	1969	1.70
Madison Unit No. 2	D	O/NG	1959	0.95
Madison Unit No. 3	D	O/NG	1953	0.85
Madison Unit No. 4	D	O	1946	0.50
McCook Unit No. 1	CT	O	1973	37.00
Minnechaduza Unit No. 1	H	HR	1930	0.22
North Platte Unit No. 1	H	HR	1936	12.00
North Platte Unit No. 2	H	HR	1936	12.00
Ord Unit No. 1	D	O/NG	1973	4.00
Ord Unit No. 2	D	O/NG	1966	1.50
Ord Unit No. 3	D	O/NG	1963	2.00
Ord Unit No. 4	D	O/NG	1947	0.80
Schuyler Unit No. 1	F	O/NG	1958	5.00
Schuyler Unit No. 2	F	O/NG	1955	3.00
Sheldon Unit No. 1	F	C	1961	105.00
Sheldon Unit No. 2	F	C	1966	120.00
Spencer Unit No. 1	H	HS	1935	1.00
Spencer Unit No. 2	H	HS	1952	0.80
Sutherland Unit No. 1	D	O	1952	0.40
Sutherland Unit No. 2	D	O	1959	0.95
Sutherland Unit No. 3	D	O	1935	0.15
Sutherland Unit No. 4	D	O	1964	1.20
Wakefield Unit No. 4	D	O/NG	1961	0.50
Wakefield Unit No. 5	D	O/NG	1966	1.00
Wakefield Unit No. 6	D	O/NG	1971	1.00

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
NEBRASKA PUBLIC POWER DISTRICT (Cont'd)				
UNIT NAME	**UNIT** TYPE**	**FUEL** TYPE**	**YEAR OF COMMERCIAL OPERATION**	**SUMMER CAPACITY MW**
Wayne Unit No. 1	D	O	1952	0.75
Wayne Unit No. 3	D	O	1956	1.75
Wayne Unit No. 4	D	O	1960	1.85
Wayne Unit No. 5	D	O	1966	3.25
Wayne Unit No. 6	D	O	1968	4.90
TOTAL				2710.92

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
OMAHA PUBLIC POWER DISTRICT				
UNIT NAME	UNIT** TYPE	FUEL** TYPE	YEAR OF COMMERCIAL OPERATION	SUMMER CAPACITY MW
Fort Calhoun Unit No. 1	N	U	1973	476.00
Jones St Unit No. 1	CT	O	1973	54.70
Jones St Unit No. 2	CT	O	1973	54.70
Nebraska City Unit No. 1	F	C	1979	584.90
North Omaha Unit No. 1	F	C	1954	75.60
North Omaha Unit No. 2	F	C	1957	102.10
North Omaha Unit No. 3	F	C	1959	102.10
North Omaha Unit No. 4	F	C	1963	131.20
North Omaha Unit No. 5	F	C	1968	218.60
Sarpy County Unit No. 1	CT	O/NG	1972	51.40
Sarpy County Unit No. 2	CT	O/NG	1972	51.40
Tecumseh Unit No. 1	D	O	1949	0.67
Tecumseh Unit No. 2	D	O	1968	1.25
Tecumseh Unit No. 3	D	O	1952	1.06
Tecumseh Unit No. 4	D	O	1960	1.16
Tecumseh Unit No. 5	D	O	1957	0.46
TOTAL				1907.30

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
NEBRASKA MUNICIPAL POWER POOL/ MUNICIPAL ENERGY AGENCY OF NEBRASKA				
UNIT NAME	UNIT** TYPE	FUEL** TYPE	YEAR OF COMMERCIAL OPERATION	SUMMER CAPACITY MW
Ansley Unit No. 1	D	O/NG	1968	0.45
Ansley Unit No. 2	D	O/NG	1972	0.96
Arnold Unit No. 1	D	O	1960	0.50
Arnold Unit No. 4	D	O/NG	1949	0.25
Auburn Unit No. 1	D	O/NG	1982	2.40
Auburn Unit No. 2	D	O/NG	1949	1.00
Auburn Unit No. 3	D	O/NG	1947	1.00
Auburn Unit No. 4	D	O	1939	0.70
Auburn Unit No. 5	D	O/NG	1973	3.40
Auburn Unit No. 6	D	O/NG	1967	2.80
Auburn Unit No. 7	D	O/NG	1988	5.60
Beaver City No. 1	D	O/NG	1958	0.40
Beaver City No. 2	D	O/NG	1961	0.30
Beaver City No. 3	D	O	1947	0.20
Beaver City No. 4	D	O/NG	1967	0.80
Benkelman Unit No. 1	D	O	1956	0.75
Blue Hill Unit No. 4	D	O	1948	0.35
Blue Hill Unit No. 5	D	O	1964	0.85
Broken Bow Unit No. 1	D	O	1943	0.40
Broken Bow Unit No. 2	D	O/NG	1969	3.20
Broken Bow Unit No. 3	D	O/NG	1948	0.80
Broken Bow Unit No. 4	D	O/NG	1952	0.80
Broken Bow Unit No. 5	D	O/NG	1952	1.00
Broken Bow Unit No. 6	D	O/NG	1963	2.10
Burwell Unit No. 2	D	O/NG	1955	0.45
Burwell Unit No. 3	D	O/NG	1962	0.65
Burwell Unit No. 4	D	O/NG	1967	0.80
Burwell Unit No. 5	D	O/NG	1972	1.10

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
NEBRASKA MUNICIPAL POWER POOL/ MUNICIPAL ENERGY AGENCY OF NEBRASKA (Cont'd)				
UNIT NAME	UNIT** TYPE	FUEL** TYPE	YEAR OF COMMERCIAL OPERATION	SUMMER CAPACITY MW
Callaway Unit No. 1	D	O	1936	0.22
Callaway Unit No. 2	D	O	1948	0.17
Callaway Unit No. 3	D	O	1958	0.47
Chappell Unit No. 1	D	O	1947	0.14
Chappell Unit No. 3	D	O	1982	1.06
Crete Unit No. 1	D	O/NG	1939	0.48
Crete Unit No. 2	D	O/NG	1955	1.36
Crete Unit No. 3	D	O/NG	1951	1.03
Crete Unit No. 4	D	O/NG	1947	1.06
Crete Unit No. 5	D	O/NG	1962	2.68
Crete Unit No. 6	D	O/NG	1965	3.67
Crete Unit No. 7	D	O/NG	1972	5.39
Curtis Unit No. 1	D	O/NG	1975	1.22
Curtis Unit No. 2	D	O/NG	1969	1.03
Curtis Unit No. 4	D	O/NG	1955	0.75
Fairbury Unit No. 2	F	O/NG	1948	3.90
Fairbury Unit No. 3	F	O/NG	1966	11.40
Falls City Unit No. 3	D	O/NG	1965	2.75
Falls City Unit No. 4	D	O/NG	1946	0.73
Falls City Unit No. 5	D	O/NG	1951	2.00
Falls City Unit No. 6	D	O/NG	1958	2.50
Falls City Unit No. 7	D	O/NG	1972	6.25
Falls City Unit No. 8	D	O/NG	1981	6.00
Franklin Unit No. 1	D	O/NG	1963	0.68
Franklin Unit No. 2	D	O/NG	1974	1.37
Franklin Unit No. 3	D	O/NG	1969	1.14
Franklin Unit No. 4	D	O/NG	1955	0.60
Fremont Unit No. 6	F	C	1958	11.12
Fremont Unit No. 7	F	C	1963	22.00
Fremont Unit No. 8	F	C	1977	87.00

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
NEBRASKA MUNICIPAL POWER POOL/ MUNICIPAL ENERGY AGENCY OF NEBRASKA (Cont'd)				
UNIT NAME	**UNIT** TYPE**	**FUEL** TYPE**	**YEAR OF COMMERCIAL OPERATION**	**SUMMER CAPACITY MW**
Grand Island Unit No. 1	F	O/NG	1957	15.90
Grand Island Unit No. 2	F	O/NG	1963	22.30
Grand Island Unit No. 3	F	O/NG	1971	54.00
Grand Island Gas Turbine	CT	O/NG	1968	14.80
Platte Generating Station	F	C	1982	100.00
Hastings Energy Center Unit No. 1	F	C	1981	72.00
Hastings Unit No. 4	F	O/NG	1957	15.00
Hastings Unit No. 5	F	O/NG	1967	22.00
Hastings Unit No. 1	CT	O	1972	21.00
Kimball Unit No. 1	D	O/NG	1955	0.94
Kimball Unit No. 2	D	O/NG	1956	0.94
Kimball Unit No. 3	D	O/NG	1959	1.20
Kimball Unit No. 4	D	O/NG	1960	1.20
Kimball Unit No. 5	D	O/NG	1950	0.70
Kimball Unit No. 6	D	O/NG	1976	3.02
Laramie Unit* No. 1	F	C	1982	10.00
Mullen Unit No. 1	D	O	1957	0.45
Mullen Unit No. 2	D	O	1966	0.98
Nebraska City Unit No. 2	D	O/NG	1953	1.25
Nebraska City Unit No. 3	D	O/NG	1955	2.50
Nebraska City Unit No. 4	D	O/NG	1957	3.10
Nebraska City Unit No. 5	D	O/NG	1964	2.00
Nebraska City Unit No. 6	D	O/NG	1969	2.07
Nebraska City Unit No. 7	D	O/NG	1970	2.07
Nebraska City Unit No. 8	D	O/NG	1971	4.10
Nebraska City Unit No. 9	D	O/NG	1974	6.42
Nebraska City Unit No. 10	D	O/NG	1979	6.50
Oxford Unit No. 2	D	O	1952	0.40
Oxford Unit No. 3	D	O	1956	0.76
Oxford Unit No. 4	D	O	1956	0.33
Oxford Unit No. 5	D	O/NG	1972	1.22

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
NEBRASKA MUNICIPAL POWER POOL/ MUNICIPAL ENERGY AGENCY OF NEBRASKA (Cont'd)				
UNIT NAME	**UNIT** TYPE**	**FUEL** TYPE**	**YEAR OF COMMERCIAL OPERATION**	**SUMMER CAPACITY MW**
Pender Unit No. 1	D	O	1967	1.55
Pender Unit No. 2	D	O/NG	1973	2.07
Pender Unit No. 3	D	O	1953	0.56
Pender Unit No. 4	D	O	1961	0.67
Plainview Unit No. 1	D	O/NG	1939	0.95
Plainview Unit No. 2	D	O/NG	1939	0.56
Plainview Unit No. 3	D	O/NG	1939	0.50
Red Cloud Unit No. 2	D	O	1953	0.44
Red Cloud Unit No. 3	D	O	1960	0.87
Red Cloud Unit No. 4	D	O	1968	0.88
Red Cloud Unit No. 5	D	O	1974	1.81
Sargent Unit No. 1	D	O/NG	1968	1.12
Sargent Unit No. 3	D	O/NG	1964	0.90
Sargent Unit No. 4	D	O/NG	1954	0.50
Sidney Unit No. 1	D	O/NG	1949	1.25
Sidney Unit No. 2	D	O/NG	1951	2.16
Sidney Unit No. 3	D	O/NG	1931	0.74
Sidney Unit No. 4	D	O/NG	1947	1.03
Sidney Unit No. 5	D	O/NG	1955	3.13
Stuart Unit No. 1	D	O/NG	1952	0.70
Stuart Unit No. 2	D	O/NG	1960	0.30
Stuart Unit No. 3	D	O/NG	1952	0.21
Wahoo Unit No. 1	D	O/NG	1960	2.50
Wahoo Unit No. 3	D	O/NG	1973	4.42
Wahoo Unit No. 4	D	O/NG	1947	0.71
Wahoo Unit No. 5	D	O/NG	1952	2.19
Wahoo Unit No. 6	D	O/NG	1968	3.50

EXISTING GENERATING UNITS IN NEBRASKA (Based on Ownership and/or Reporting Responsibility)				
NEBRASKA MUNICIPAL POWER POOL/ MUNICIPAL ENERGY AGENCY OF NEBRASKA (Cont'd)				
UNIT NAME	**UNIT** **TYPE**	**FUEL** **TYPE**	**YEAR OF COMMERCIAL OPERATION**	**SUMMER CAPACITY MW**
West Point Unit No. 1	D	O/NG	1965	2.28
West Point Unit No. 2	D	O/NG	1959	1.14
West Point Unit No. 3	D	O/NG	1971	4.02
Wisner Unit No. 1	D	O/NG	1954	0.48
Wisner Unit No. 2	D	O	1947	0.31
Wisner Unit No. 3	D	O	1969	0.85
TOTAL				648.63

APPENDIX D

PRODUCTION COSTS

APPENDIX D

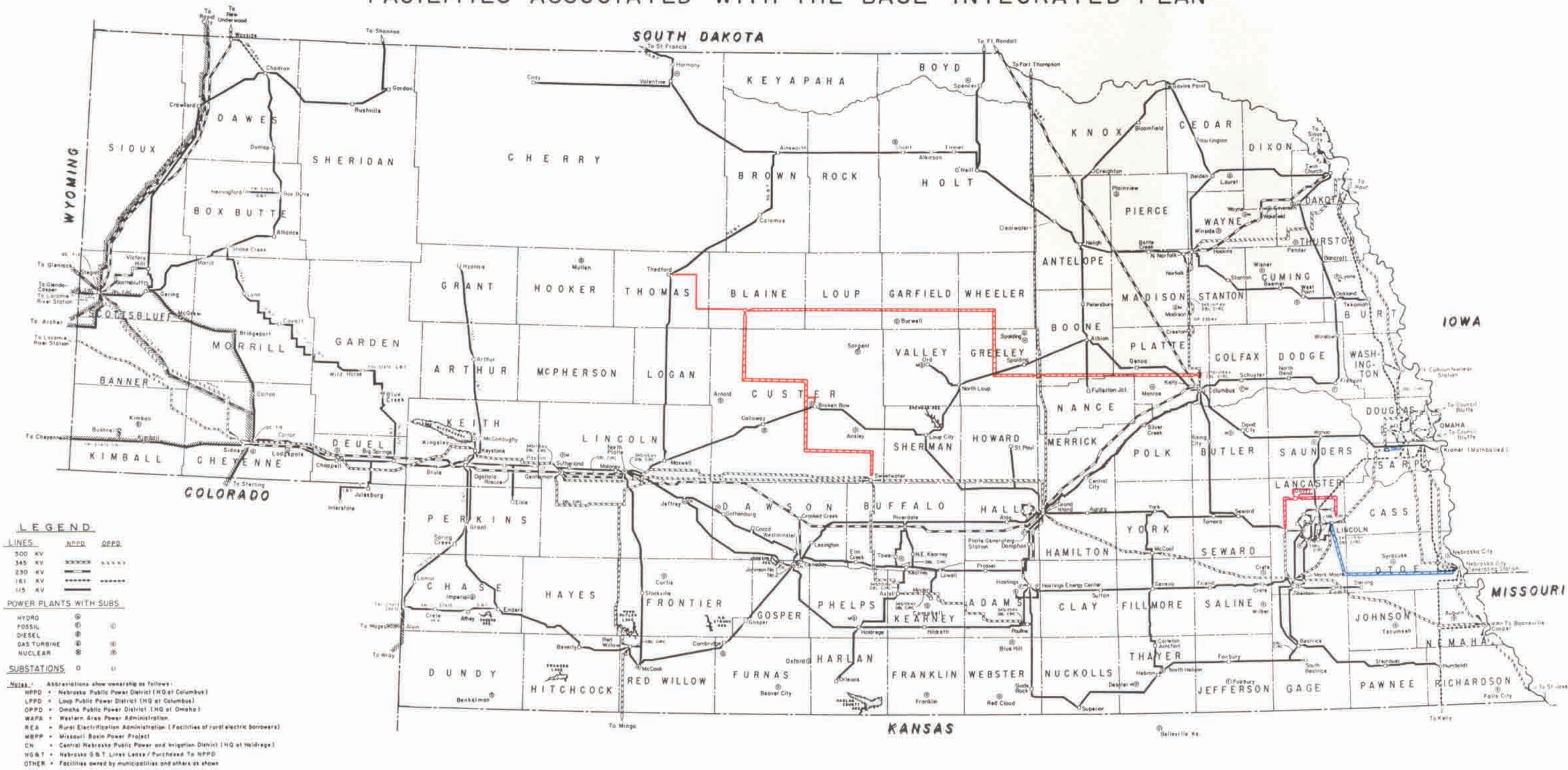
PRODUCTION COSTS FOR EXISTING UNITS (1990$)

STATION NAME	LOCATION	NO. OF UNITS	CAPACITY (MW)	FUEL COST $/MMBTU	FUEL COST AT FULL LOAD ($/MWH)	VARIABLE O&M COST $/MWH
Fort Calhoun Nuclear	Blair, Nebr.	1	476	0.55	5.9	1.0
Cooper Nuclear	Brownville, Nebr.	1	389*	0.51	5.4	1.0
Gentleman Station	Sutherland, Nebr.	2	1,278	0.70	7.0	1.3
Laramie River Station	Wheatland, Wyo.	1	183*	0.65	6.6	2.0
Nebraska City Station	Nebraska City, Nebr.	1	585	0.75	7.8	1.3
North Omaha Station	Omaha, Nebr.	5	590	0.75	8.3	2.0
Sheldon Station	Hallam, Nebr.	2	225	0.84	9.3	2.0
Fremont Station	Fremont, Nebr.	3	120	0.85	9.5	2.0
Platte Generating Station	Grand Island, Nebr.	1	100	0.85	9.2	2.0
Hastings Energy Center	Hastings, Nebr.	1	72	0.85	9.0	2.0
Canaday Station	Lexington, Nebr.	1	107	2.31	23.8	1.0
Diesels Statewide	Various	140	209	2.76	31.8	4.3
Comb. Turbines Statewide	Various	11	449	3.45	45.5	4.3
Small Fossil Statewide	Various	9	153	2.65	32.1	2.7
****TOTAL Nuclear & Fossil**			4935			

* Nebraska utility participation share only
** Does not include 161 MW of hydroelectric facilities

APPENDIX E
TRANSMISSION MAP

NEBRASKA POWER ASSOCIATION
STATEWIDE TRANSMISSION PLANNING STUDY
FACILITIES ASSOCIATED WITH THE BASE INTEGRATED PLAN



KEY TO TRANSMISSION FACILITIES:

BLACK — Existing Facilities Or Facilities Committed To Be In Service By Year 2005

BLUE — Facilities Associated With A Second 600 MW Unit Addition At Nebraska City (In Service In 2005)

RED — Facilities Associated With The First 600 MW Unit Addition North Of Lincoln

ORANGE — Facilities Associated With The First 600 MW Unit Addition In Blaine County

TE: A 600 MW Coal Unit is added in 2008. An evaluation of various factors would determine at which of these two future sites this unit would be located.

APPENDIX F
SUPPLY-SIDE ALTERNATIVES

APPENDIX F

BACKGROUND DESCRIPTION OF THE SUPPLY-SIDE ALTERNATIVES

The Integrated Planning Task Force evaluated a variety of supply-side alternatives as discussed in Section 4.7.1. A general description of each alternative is included in this appendix. This information is also summarized in Table F-1.

CONVENTIONAL COAL - 600 MW

The coal is pulverized and burned in suspension in a large boiler producing steam which then drives the steam turbine generator set. This is the predominant technology for producing electricity in the U.S., supplying over 50 percent of the annual generation. The conventional units represented in this Study burn low sulfur, low cost, strip-mined coal, most likely from the Powder River Basin in Wyoming. Because of the low sulfur content of the coal and the use of sulfur removal technology in the flue gas (scrubber), sulfur emissions from these units are relatively low. Nitrogen oxide (NO_x) emissions are moderate and controlled by low NO_x burners. Carbon dioxide (CO_2) emissions are relatively high because of the high carbon content of the coal and because feasible removal technology does not exist. Sites in east-central and eastern Nebraska were assumed for the Study. Although capital costs for these baseload units are high compared to peaking and intermediate technologies such as combustion turbines and combined cycle units, the energy costs are amongst the lowest in the country.

NEBRASKA CITY UNIT NO. 2 - 600 MW

Unit 2 at Nebraska City would be a second unit at the existing site along the Missouri River. The unit is basically the same as the sub-bituminous conventional coal units. The lower capital costs result from the shared use of existing transmission and generation facilities installed with the first unit.

CONVENTIONAL COAL - 300 MW

This is the same unit as the 600 MW conventional coal unit, only smaller in size. Although the smaller size may allow capacity additions to more closely match load growth, the capital and fixed O&M costs per unit of capacity are noticeably higher. Other characteristics are nearly identical to the 600 MW coal unit.

CONVENTIONAL COAL - 250 MW

This is a conventional coal unit of the same characteristics as the 600 and 300 MW units, except that costs are based upon a second unit at potential existing sites in Nebraska such as Grand Island, Hastings, or the Gerald Gentleman Station. This results in capital and fixed O&M costs that are somewhat lower per unit ($/KW) than for the 300 MW unit because of previous investment in facilities at the existing sites.

COMBUSTION TURBINE

A combustion turbine burns a gaseous or liquid fuel with compressed air producing hot gases which drive an expansion turbine connected to a generator. Although the cost to construct these units is quite low, the relatively high cost of the gaseous or liquid fuels compared to coal costs in this area makes these units suitable for meeting loads which only occur a limited number of hours during the year such as air conditioning loads in the summer or peak heating loads in the winter. Nitrogen oxide emissions from these units have the potential to be moderate but are reduced to very low levels by injecting steam or water into the combustors. Carbon dioxide emissions are about one-half those of coal units because of the use of natural gas. The units would also be capable of burning oil in the event that oil was more economical or gas was unavailable. Another advantage of these units is that they require only a small site and can be located relatively close to population centers.

COMBINED CYCLE

In a combined cycle unit, hot gases from the expansion turbine of a combustion turbine are used to produce steam and drive a steam turbine generator set. This results in a unit which is more expensive to build than a combustion turbine but produces a larger output and operates more efficiently. It is ideal for meeting loads which occur more frequently than those met most economically by combustion turbines but which occur less frequently than the nearly year-round loads met most economically by baseload resources. Other characteristics of the unit are very similar to those of the combustion turbine.

MOLTEN CARBONATE FUEL CELL

Expected to be commercially available in the mid to late 1990's, this fuel cell technology converts chemical energy from natural gas to direct current electricity. Conceptually, a fuel cell is similar to a battery with continuous addition of chemical energy through a fuel containing hydrogen. Carbon dioxide and water are the primary byproducts of the reaction. Fuel cells are expected to provide the highest efficiencies and the lowest emissions of any generating technologies existing or expected to be commercial this decade. Other advantages include their small size, modular construction, fast response time to load changes, and the ability to site them adjacent to or in load center areas. The molten carbonate fuel cell is expected to be operated primarily as an intermediate or baseload unit. Commercial success depends upon the ability to reach capital cost targets and to extend the life of and reduce the cost of the fuel cell stacks themselves.

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

IGCC units are integrated systems of a coal gasifier, combustion turbines, and steam turbines. The Cool Water Project located at Dagget, California successfully demonstrated utility operation of a commercial IGCC unit. Some commercial orders for IGCC units have been placed. The integration of coal gasification with combustion and steam turbines provides the potential advantage of lower heat rates and lower emissions. Commercial success will depend upon keeping capital and maintenance costs of the units competitive with conventional coal technologies. These plants also have the advantage of staged additions. The combustion turbine or combined cycle portion of the plant can be installed in a short time to meet peaking or intermediate load requirements. The coal gasification portion and the integration of the units is done at a later time to burn coal for baseload operation.

COMPRESSED AIR ENERGY STORAGE (CAES)

This energy storage technology is based on using low cost electricity from nuclear or coal units to compress air in an underground cavern or reservoir during off-peak periods such as nights or weekends. When generation is needed, the compressed air is expanded through a combustion turbine that is also fired with natural gas or distillate fuel. There is at least one CAES unit under construction in the United States. This 110 MW unit, located at McIntosh, Alabama, is scheduled for commercial operation in 1991 and utilizes salt caverns for storage. Potential sites exist in Nebraska for conventionally mined rock caverns or aquifer reservoirs sized for ten hours of generating capacity. Although the capital cost of a CAES unit is higher than a combustion turbine, it offers advantages of lower energy cost than a combustion turbine and the more complete use of baseload resources during low load periods. Direct emissions from the CAES unit are lower than for a combustion turbine because of the reduced fuel use, but total emissions to produce the electricity are dependent upon the generation source for providing electricity to compress and store the air.

ADVANCED BATTERY ENERGY STORAGE

The advanced energy storage battery is expected to be available in the late 1990's. Twenty megawatt units with five hours of energy storage use either sodium-sulfur or zinc-bromine systems. The battery is charged during off-peak periods using energy from low cost baseload units. The battery is then discharged to meet peak period loads. Advantages of the battery are its small size, modular construction, virtually zero emissions, and a very fast response time to load. Commercial competitiveness will depend primarily upon the final capital cost and the expected life of the battery cells. Also the need to convert between alternating and direct current adds to the cost. Environmental emissions of the batteries are nearly zero but total emissions to produce electricity depend upon the generating source for charging the batteries.

ADVANCED NUCLEAR

To achieve a design that is less complex, the NRC, utilities, and manufacturers are working on conceptual designs for 600 MW passive reactors. Passive means, such as gravity or convection, are used in the advanced safety systems. This concept allows for a simpler plant design. The reduction in necessary parts and material and a shorter construction period will hopefully lead to lower capital costs, making nuclear power more competitive than it is today. Commercial availability is expected about 2002.

PUMPED STORAGE

The pumped hydro energy storage alternative is based on 350 MW units consisting of a water turbine, a generator, and an upper and lower reservoir. Water is pumped from the lower to the upper reservoir using off-peak electricity. During the generating cycle, water is discharged through the reversible turbine generators to produce power. Designs and costs are site specific with a typical storage capacity of ten hours per day. The economics of a pumped storage unit depend upon the magnitude of the difference between off-peak energy used to pump the water and the cost of on-peak energy displaced by generation from the unit compared to the capital cost of the project. Environmental emissions are nearly zero at the site, but total emissions to produce electricity depend upon the generation source for pumping water to the upper reservoir.

WOOD

Wood is available in large quantities in some areas as a byproduct of wood processing industries such as paper and saw milling operations. Wood wastes are generally fired in a boiler to produce steam to drive a turbine generator set. Some of the steam which exits the turbine is used as process steam in nearby plants. Wood burns relatively cleanly with few of the pollutants associated with coal. Since most wood is currently burned in association with wood processing industries, production of electricity from wood would require that it be harvested specifically for electric generation. There is a definite shortage of trees in Nebraska. To remain competitive, wood cannot be shipped over great distances.

SOLAR PHOTOVOLTAIC CENTRAL STATION

Photovoltaic power generation converts solar energy to direct-current electricity through individual solar cells. For this plant, concentrators optically focus direct sunlight onto a smaller area. Since sunlight is a diffuse source of energy, large land areas are required to produce significant quantities of electricity. Because of the variation in the intensity of sunlight, because of the movement of the sun, and the interference from poor weather, the best sites for solar photovoltaic are in the southwestern United States. Limited energy output makes solar units best for peaking or intermediate operation. Many times however, there is a good correlation between sunlight intensity and utility peak loads. Although sunlight is free, high capital costs and, in some cases, high maintenance costs block the commercial competitiveness of this technology for most of the U.S.

SOLAR THERMAL CENTRAL STATION

Oil, heated by the sun while it moves through a parabolic-trough solar collector, produces steam in a steam generator. This steam then drives a turbine generator set. Since solar energy is diffuse, a large land area is required for this plant. Solar intensity varies with season and with the time of the day with the greatest intensities coming in the month of June and during the midday hours. Since weather also affects the availability of sunlight, the best locations for these plants are the deserts of the southwestern United States. These units are used primarily for peaking or intermediate loads because of their limited output. Although the sunlight is free, the capital costs of constructing the plant and the high cost of maintenance are the primary obstacles to commercial competitiveness in most of the U.S. The Luz Corporation has commercialized about 190 MW of this solar technology in southern California.

ATMOSPHERIC FLUIDIZED BED COMBUSTION (AFBC)

An AFBC unit is similar to a conventional pulverized coal unit. All basic equipment is generally the same except for the furnace or boiler and the means of sulfur removal. Crushed coal is burned with limestone in a "fluidized bed" suspended by air blown in from below. The calcium in the limestone captures most of the sulfur present in the coal that would otherwise have been released into the flue gas during conventional combustion. Sulfur dioxide emissions are low and NO_x emissions are moderate to low. As with conventional coal units, AFBC units are primarily used as baseload resources. Four AFBC plants, ranging in size from 80 to 160 MW, have been constructed and started operation in the United States for demonstration or commercial use by utilities. The practical size limit for a simple AFBC boiler is currently 200 MW. The primary advantage of a AFBC unit is its fuel flexibility, such that boiler design is only moderately affected by coal properties.

WIND

Commercial wind turbine designs generally range in size from 100 kW to 300 kW and produce electrical power at wind speeds exceeding 12 mph. Since the energy from the wind increases with the cube of the windspeed, cost effective wind turbine units must be located at sites with good wind speeds and use reliable, efficient turbines. Multiturbine wind generation sites produce energy sufficient for peaking to intermediate loads depending upon the wind velocity. Wind turbine capacity cannot always be counted upon to meet peak loads because of the variability of the wind. Most wind turbine projects in the U.S. have been located at three sites in California with high average wind speeds created by air movements through low mountain passes.

MUNICIPAL SOLID WASTE

About 75 percent of the municipal solid waste that is used to generate energy in the United States uses a mass burn technology. Up to three to four days supply of solid waste is stored on site and burned on a reciprocating grate in a furnace. Sulfur dioxide, hydrogen chloride and other gases are removed by scrubbing the flue gas. Fly ash and particulates are removed by a bag house. Questions of potential toxicity in the fly ash and bottom ash are being addressed in federal regulations. The initial capital and the ongoing maintenance costs of these plants are very high. They are used as a means to dispose of solid waste in those areas of the country where landfill is no longer available or where the tipping fees charged for the dumping of solid waste are sufficiently high to compensate for the high plant costs.

TABLE F-1
SUPPLY SIDE ALTERNATIVES (1990$)

	Nebraska City #2	Conventional Coal	Conventional Coal	Conventional Coal	Combustion Turbine	Combined Cycle
Fuel	Sub-bituminous Coal	Sub-bituminous Coal	Sub-bituminous Coal	Sub-bituminous Coal	Natural Gas	Natural Gas
Electric Conversion Process	Boiler/ Steam Turbine	Boiler/ Steam Turbine	Boiler/ Steam Turbine	Boiler/ Steam Turbine	Compressor & Turbine	Combustion Turbine & Steam Turbine
Size (MW)	600	600	300	250	80	150
Typical Operation	Baseload	Baseload	Baseload	Baseload	Peaking	Intermediate
Availability	High	High	High	High	Very High	Very High
Technology Status	Mature	Mature	Mature	Mature	Mature	Mature
Cost Estimate Confidence Rating	Preliminary	Preliminary	Preliminary	Preliminary	Preliminary	Preliminary
Cost: Overnight Const. Cost ($/KW) Fixed O&M, A&G, Ins. ($/KW-yr) 2005 Fuel+Variable O&M ($/MWH)	1,070-2nd 20.90 9.42	1,297-1st 1,094-2nd 23.90 9.42	1,620-1st 1,331-2nd 33.50 9.62	1,262-2nd 28.50 9.62	350-1st 298-2nd 5.50 40.81	582-2nd 10.50 26.73
Environmental: Relative Emissions SO_2 NO_x CO_2	Low Moderate High	Low Moderate High	Low Moderate High	Low Moderate High	Very Low Very Low Moderate	Very Low Very Low Moderate
Transmission Requirements	Extensive	Extensive	Extensive	Extensive	Limited	Limited to Moderate
Siting Requirements	Existing; Large & Near Load Center	New; Large & Near Load Center to Distant	New; Large & Near Load Center to Distant	Existing; Large & Near Load Center to Distant	New; Small & Near or Adjacent to Load Center	New; Small & Near or Adjacent to Load Center
Lead Times (Years)	8	9	8	8	3	5

TABLE F-1
SUPPLY SIDE ALTERNATIVES (1990$) (Cont'd)

	Molten Carbonate Fuel Cell	Integrated Gasification Combined Cycle	Compressed Air Energy Storage	Advanced Battery 5-HOUR	Advanced Nuclear	Pumped Storage
Fuel	Natural Gas	Coal	Natural Gas & Stored Compressed Air	Stored Chemical Energy	Uranium	Elevated Stored Water
Electric Conversion Process	Electro-Chemical	Coal Gasif./Comb. Turb./Steam Turb.	Combustion Turbine	Electro-Chemical	Fission/ Steam Turb.	Water Turbine
Size (MW)	11.1	500	110	20	600	350
Typical Operation	Intermediate/ Baseload	Baseload	Peaking/ Intermediate	Peaking	Baseload	Peaking/ Intermediate
Availability	Very High	High	Moderate 10 Hrs. Day	Low 5 Hrs. Day	High	Moderate 10 Hrs. Day
Technology Status	Laboratory/ Pilot Plant	Demonstration/ Comm. Orders	Mature[3]	Pilot	Pilot	Mature
Cost Estimate Confidence Rating	Simplified/ Preliminary	Preliminary	Preliminary	Goal	Goal	Preliminary
Cost:						
Overnight Const. Cost ($/KW)	591	1,534	544	668	1,549	1,100
Fixed O&M, A&G, Ins. ($/KW-yr)	27.0	35.00	5.20	4.00	108.00	13.50
2005 Fuel+Variable O&M ($/MWH)	22.34	10.10	20.86[4]	14.78[4]	5.50	12.74[4]
Environmental:						
Relative Emissions SO_2	Lowest[1]	Very Low	Very Low[2]	Nearly Zero[2]	None	Nearly Zero[2]
NO_x	Lowest[1]	Very Low	Very Low[2]	Nearly Zero[2]	None	Nearly Zero[2]
CO_2	Lowest[1]	High	Low[2]	Nearly Zero[2]	None	Nearly Zero[2]
Transmission Requirements	Limited/ Distrib. Only	Extensive	Moderate to Limited	Limited/ Distrib. Only	Extensive	Extensive
Siting Requirements	Very Small/ Distribution Level/Adjacent to Load Center	Large/Distant to Near Load Center to Distant	Small/Near or Adjacent to Load Center	Very Small/ Distribution Level/Adjacent to Load Center	Large/ Distant	Large/ Distant
Lead Times (Years)	2	5	4	2	9	10

[1]Lowest of generating units.
[2]Does not include emissions from generating unit used to store the energy.
[3]One commercial unit under construction in the United States.
[4]Includes Fuel + Variable O&M from the generating unit (large coal) used to store the energy.

TABLE F-1
SUPPLY SIDE ALTERNATIVES (1990$) (Cont'd)

	Wood	**Solar Photovoltaic Central Station**	**Solar Thermal Central Station**	**Atmospheric Fluidized Bed**	**Wind**	**Municipal Solid Waste**
Fuel	Wood	Solar Insolation	Solar Insolation	Coal	Wind	Refuse
Electric Conversion Process	Boiler/Steam Turbine	High Concentration Photocells (Direct)	Parabolic Trough Collection/ Steam Turb.	Circulating Bed Boiler Steam Turb.	Wind Turbine	Mass Burn
Size (MW)	30	20 Units at 5 MW	80	200	200 Units at 0.3 MW	80
Typical Operation	Intermediate/ Base	Intermediate	Intermediate	Baseload	Intermediate	Intermediate/ Baseload
Availability	High	Daytime & Variable	Daytime & Variable	High	Highly Variable Seasonally & Daily	Moderate & Variable
Technology Status	Mature	Laboratory	Mature	Demonstration	Mature	Mature
Cost Estimate Confidence Rating	Preliminary	Goal	Preliminary	Preliminary	Simplified	Preliminary
Cost: Overnight Const. Cost ($/KW) Fixed O&M, A&G, Ins. ($/KW-yr) 2005 Fuel+Variable O&M ($/MWH)	1,618 68.10 14.23	2,704 13.90 7.80	2,926 51.80 0.80	1,581 39.17 11.74	1,724 12.00 6.20	4,736 131.25 -15.6
Environmental: Relative Emissions SO_2 NO_x CO_2	Low Low Moderate	None None None	None None None	Very Low Moderate High	None None None	Variable Variable Variable
Transmission Requirements	Moderate	Moderate to Extensive	Moderate to Extensive	Extensive	Extensive to Moderate	Moderate to Limited
Siting Requirements	Small to Moderate/ Distant to Near Load Center	Large/Best in South-western U.S.	Large/Best in South-western U.S.	Large/ Near Load Center to Distant	Large/ Near Load Center to Distant	Moderate to Small/Near or Adjacent to Load
Lead Times (Years)	5	4	2	6	2	6

APPENDIX G

BASE AND SENSITIVITY CASES

APPENDIX G

BACKGROUND DESCRIPTION OF THE BASE AND SENSITIVITY CASES

The base case is the best estimation of the current business environment. Under certain circumstances any of a number of the variables involved may change slightly or significantly. Sensitivity cases are required to test the significance of the uncertainties inherent in the variables. The primary areas of sensitivity examined are the DSM participation rate, discount rate, load forecast, fuel costs, capital costs and environmental costs.

Table G-1 depicts the major supply-side variables and how they vary in each of the nine sensitivity cases. The DSM participation rate variables are shown in Table 4.7.4.2-1.

The Base case depicts the Integrated Planning Task Force's best estimate of the major study variables. Six primary areas of uncertainty are identified, these being:

Discount Rate:	The rate at which revenue requirements are discounted. The base rate is 8 percent. (See Section 4.3).
Load Forecast:	The projected demand and energy requirements of the state. The base growth rate for peak demand is 1.6% per year. The base energy growth rate is 2.0% per year. (See Section 4.1.2).
Fuel Costs:	The projected cost of coal, natural gas, oil, and uranium.
DSM Participation:	The percentage of eligible customers who elect to participate in a given DSM program. Specific rates by program are given in Table 4.7.4.2-1.
Capital Costs:	The projected capital cost of adding resources to meet future demand requirements. (See Appendix F).

Environmental Costs: The allowance for uncertain future environmental costs. (See Section 4.5).

<u>DSM Participation Rate cases</u> - differ from the Base case in that higher and lower customer participation rates are studied as detailed in Table 4.7.4.2-1.

<u>High Discount Rate case</u> - differs from the Base case only in that cost results are discounted at 12%. The base assumption of 8% is referenced to the interest rate for tax-free bonds used by public utilities to finance projects. The 12% rate reflects what it costs the rate payers (customer owners) to borrow money.

<u>HR 4805 Carbon Tax case</u> - differs from the Base case in that the carbon tax proposed in the HR 4805 bill is added to the cost of the fuels. Beginning in 1991, a $.90/MMBtu tax on coal, $.40/MMBtu on natural gas, and $.56/MMBtu on oil is implemented and is phased in over a five-year period. This results in an increase of $15/ton for coal, an increase of 7.7 cents/gallon for oil, and an increase of 4 cents/ccf for natural gas.

<u>High Load Growth case</u> - differs in the rate at which electrical peak demands and energy needs grow within the state. Each utility supplies the growth rates they believe their individual systems will experience. The Base case has a statewide composite growth rate for peak demand during the years 1990-2019 of 1.6% per year. Energy need grows at just less than 2.0% per year. The high forecast used in this case has rates of 2.3% per year for demand and 2.7% per year for energy each during the same time frame.

<u>Low Load Growth case</u> - differs only in that its growth rates are less than the Base case. The peak demand growth rate is 0.9% per year and the energy need growth rate is 1.2% per year for the 1990-2019 period.

Clean Coal Technology case - differs from the Base case in that equipment meeting new source performance standards is required on units. Future resources such as combustion turbines and combined cycle units will require SCR equipment, and future pulverized coal units will be replaced by IGCC units.

High Natural Gas Fuel Cost case - differs in its costs of natural gas and oil. The Base case uses a gas cost of $2.31/MMBtu in 1990 escalating yearly at 2% real for the remainder of the Study. Oil is estimated at $0.56/gallon escalating yearly at 2% real. For the High Gas Cost case, escalation rates remain the same but initial prices are $3.00/MMBtu for gas and $.73/gallon for oil reflecting a 30% increase over Base case levels.

High Coal Fuel Cost case - adds 25 cents per MMBtu in 1990 to each coal resource over the fuel cost levels of the Base case. This results essentially in a 33% increase in the cost of coal across the entire state.

Higher Combustion Turbine Capital Cost case - differs in the construction costs associated with combustion turbines and combined cycle units. The Base case capital costs are $324/KW and $582/KW for the average combustion turbine and combined cycle units, respectively. This case increases the overnight construction costs such that combustion turbines are $450/KW (39% increase) and combined cycle units are $733/KW (26% increase). Combined cycle costs increase by two-thirds that of combustion turbines as that is the percentage of capacity from the combustion turbine portion, the remaining one-third comes from a steam turbine.

Higher Coal Unit Capital Cost case - differs from the Base case in its estimate of coal unit construction costs. Overnight construction costs associated with Nebraska City #2, Future 600 MW Coal, and 250 MW expansion units increase by 20 percent over values found in the Base case.

Table G-1

Basic Assumptions of the Supply-Side Sensitivity Cases

(1990 $'s)

	Base Case	HR 4805 Carbon Tax	Clean Coal	Fuel Prices Gas + 30%	Fuel Prices Coal + 33%	Capital Prices CT + 39%	Capital Prices Coal + 20%	High Load Forecast	Low Load Forecast	12% Discount
Discount Rate	8%	8%	8%	8%	8%	8%	8%	8%	8%	12%
Load Forecast*	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	2.3%	0.9%	1.6%
Fuel Costs ($/MMBTU)										
Coal - New	$0.75	$0.75	$0.75	$0.75	$1.00	$0.75	$0.75	$0.75	$0.75	$0.75
Gas	$2.31	$2.31	$2.31	$3.00	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31
Oil	$4.10	$4.10	$4.10	$5.32	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10
Overnight Construction Costs ($/kW)										
Comb. Turb.	$324	$324	$324	$324	$324	$450	$324	$324	$324	$324
Comb. Cycle	$582	$582	$582	$582	$582	$733	$582	$582	$582	$582
Coal Unit	$1,194	$1,194	$1,194	$1,194	$1,194	$1,194	$1,433	$1,194	$1,194	$1,194
Other	—	Note 1	Note 2	—	—	—	—	—	—	—

* Peak Demand Growth Rate 1990-2019.

Note 1: Includes the carbon tax proposed in bill HR 4805.
Estimates: $15/ton of coal, 7.7¢/gallon for oil, 40¢/mcf for natural gas.

Note 2: Includes SCR's on all Combustion Turbine & Combined Cycle units.
Replaces Conventional Pulverized Coal Units with IGCC's.