NEBRASKA POWER ASSOCIATION

STATEWIDE
COORDINATED LONG RANGE
POWER SUPPLY PLAN
INCLUDING RESEARCH AND CONSERVATION
REPORT
(2003 - 2022)

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Prepared by: NPA Joint Planning Subcommittee

Grand Island Utilities
Hastings Utilities
Lincoln Electric System
Loup River Public Power District
Nebraska Electric G&T
Nebraska Public Power District
Municipal Energy Agency of Nebraska
Omaha Public Power District
South Central Public Power District
Tri-State G&T Association

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List of Acronyms

AN	Aquila Networks
BPS	Beatrice Power Station
CC	Combined Cycle
CT	Combustion Turbine
DSM	Demand-Side Management
EPRI	Electric Power Research Institute
FRET	Fremont Utilities
GRSP	Generation Reserve Sharing Pool (of MAPP)
GRIS	Grand Island Electric Department
HU	Hastings Utilities
IPTF	Integrated Planning Task Force (of NPA)
IRP	Integrated Resource Plan
JPS	Joint Planning Subcommittee (of NPA)
LES	Lincoln Electric System
MAPP	Mid-Continent Area Power Pool
MEAN	Municipal Energy Agency of Nebraska
MEC	MidAmerican Energy Company
NDEQ	Nebraska Department of Environmental Quality
NMPP	Nebraska Municipal Power Pool
NPA	Nebraska Power Association
NPPD	Nebraska Public Power District
NRC	Nuclear Regulatory Commission
OPPD	Omaha Public Power District
PRB	Power Review Board
PSD	Prevention of Significant Deterioration
REC	Renewable Energy Credit
RTC	Regional Transmission Committee (of MAPP)
SPG	Subregional Planning Group
TPSC	Transmission Planning Subcommittee (of MAPP)
TRC	Tradable Renewable Certificate
TSGT	Tri-State G&T Association
WAPA	Western Area Power Administration

1.0 EXECUTIVE SUMMARY

The purpose of this report is to inform the Nebraska Power Review Board (PRB) as to the status of future electrical loads and resources on a Statewide basis per their June 2002 request. The method of compiling this report is to summarize the combined results of individual Nebraska utility Integrated Resource Plans (IRPs) into a Statewide report following the scope approved by the PRB in July of 2002. The resulting Statewide Coordinated Long Range Power Supply Plan considers both Demand Side Management (DSM) programs and Supply Side resources including renewable resources. Data is reported over the next 20 years and, as such, fulfills the requirements of State Statutes 70-1025 and 70-1026.

The 2002 actual non-coincident peak load for Nebraska was 5,890 MW. The Statewide forecast of non-coincident peak demand is 5,875 MW in 2003, increasing to 8,276 MW in 2022. This is a compounded annual growth rate of 1.82% through 2022, which is essentially the same as the 2001 NPA report. Load growth in urban areas continues to be higher than rural areas. In addition to the peak load requirements, utilities are required to maintain a 15% reserve margin which in total is the Minimum Obligation. Most Nebraska utilities keep an additional margin to prepare for weather related risk which results in a higher Planned Obligation.

The load forecasts include 569 MW (in the year 2005) of DSM. The largest component of Nebraska DSM is irrigation load control (386 MW or 68%), which shifts demand from on-peak load periods to off-peak load periods. The other DSM programs are curtailable loads of large industrial/commercial customers, residential load control, efficiency, rate incentives, distributed generation, real time pricing, and educational programs. Most Nebraska utility's research projects focus on renewable type resources such as wind and bio-mass.

Nebraska currently has 6,725 MW of existing generation (which includes 505 MW that is currently under construction to be completed by this summer), about 1,064 MW of committed generation additions, and about 2,213 MW of planned and studied generation through 2022. Existing resource capabilities have increased 616 MW since the 2001 NPA report. Natural gas fired units account for 314 MW (30%) of the 1,064 MW of committed generation additions. The gas fired committed resources are 19 MW of CT capacity and 295 MW of CC capacity. The remaining 750 MW of committed resources are from two coal fired plants: Nebraska City #2 (600 MW) and Nebraska utility's share of Council Bluffs #4 (150 MW). Planned generation facilities are 220 MW of coal-fired capacity at Whelan Energy Center Unit #2 in 2007.

Committed resources are those approved by the PRB, planned are those that utilities have authorized expenditures but have not had PRB approvals, and studied are those additional resources needed to meet the Planned Obligation. A portion of the existing and committed resources are renewable, including the existing hydro facilities or contracts. There are currently four wind turbine sites (Springview, Lincoln, Valley, and Kimball). The total nameplate is 14 MW which is currently not accredited. A methane landfill gas project by Omaha Public Power District (OPPD) added 3 MW in 2002 and OPPD is studying a 3 MW expansion by 2005. The Nebraska Public Power District (NPPD) is performing a business case evaluation for up to 50 MW of wind generation for operation by fall 2004.

A capacity deficit for Nebraska, with committed resources, is not expected until 2013 based on the Planned Obligation and 2014 based on the Minimum Obligation. A capacity deficit for Nebraska, with committed and planned resources, is not expected until 2014 based on either the Planned or Minimum Obligation. The plan determined that, by 2022, the state will need approximately 1000 MW of base load, 400 MW of intermediate and 300 MW of peaking type resources.

The Nebraska Subregional Planning Group (Nebraska SPG) addressed the transmission requirements of the state statutes. The Nebraska SPG is organized under MAPP and develops a coordinated ten-year transmission plan for Nebraska on a biennial basis. The Nebraska Subregional Transmission Plan was published in April of 2002. This document includes a detailed listing of all planned transmission lines and facility upgrades required to accommodate the projected needs for the Nebraska subregion from 2002-2011. Regarding the transmission requirements for future power supply options, there are detailed transmission plans developed and approved for committed generation sites. Preliminary screening studies have also been performed for many of the proposed future generation sites, but detailed analysis is still required to develop the final transmission plans. Firm commitments for capacity and specific site locations must be completed before the transmission plans can be finalized. Based on the need to accommodate an additional 1727 MW of new peaking, intermediate, and baseload generation, significant future transmission additions could be required in the state of Nebraska.

As always, planning is an ongoing process where decisions are made on current expectations. Longer term plans may alter as these expectations change.

2.0 INTRODUCTION AND PURPOSE

2.1 Introduction

The Nebraska electric utility joint planning efforts date back to the late 1970s. The current Joint Planning Subcommittee (JPS) of the Nebraska Power Association (NPA) was formed in 1980.

Nebraska statutes provide that the Nebraska Power Review Board (PRB) designate a representative organization to be responsible for preparing reports and studies for their use. The PRB has designated the NPA as the representative organization with the JPS as the NPA sub-committee that accumulates and prepares these reports and studies.

The JPS is made up of 10 member companies with expertise in electric utility planning, representing all the major electric suppliers in Nebraska.

The JPS has prepared various joint reports and joint studies through the years for the industry and for the PRB (see Appendix A for listing). The most recent report for the PRB was Statewide Integrated Resource Planning Summary (2001-2020) dated August 2001.

As provided by statutes, the PRB can request NPA to prepare both a coordinated long range power supply plan and a research and conservation report. Either report cannot be requested more often than biennially.

In addition statutes require that an annual load and capability report be prepared by NPA and filed with the PRB.

The PRB in July, 2002, approved a Scope of Work they had requested from the NPA. This study was to be prepared by the NPA utilizing a somewhat different methodology than previous studies and was to meet the requirements for a coordinated long range power supply plan, a research and conservation report, and provide the annual load and capability report. This report is that requested document.

2.2 Purpose of Report

The purpose of this report is to meet the PRB June 2002 request of the NPA for a Coordinated Long-Range Power Supply Plan and a Research and Conservation Report. Additionally, it includes the statewide annual Load and Capability Report.

This report was prepared utilizing the Scope of Work approved by the PRB in July 2002 which stated the following:

- The report will cover loads over a 20-year period beginning with the year the report is prepared and will be prepared to provide information for power resource addition approval decisions by the Board as well as each electric supplier and will contain at least the following items:

- An estimate of the electric power requirements for each electric supplier operating in Nebraska for each year of the 20-year period based on their 50/50 load forecasts and the minimum 15% reserve requirements (minimum obligation) and then summed for a statewide total minimum obligation for each year.

- An estimate of electric power requirements for each electric supplier operating in Nebraska for each year of the 20-year period that includes any additions to the minimum obligation due to analysis based on risk assessment of items such as weather, electric markets or other items that each electric supplier uses as their load obligation for planning purposes (load obligation) and then summed for a statewide total load obligation for each year.

- Identification of all existing power supply resources and an indication as to whether they are expected to continue for the 20-year period.

- A list of new power supply resources that are committed (approved by Board) for each year by each electric supplier and a statewide total.

- A list of new power supply resources that are planned (approved by electric supplier) for each year by each electric supplier and a statewide total.

- A list of power supply resources needed beyond those committed and planned that are required by each electric supplier (for each year) to meet their load obligation for each year and by each generation type (peaking-intermediate-base) along with a summation for the state for each year.

- A listing of all demand side resources by electric supplier that are included in the load forecasts or if not included that will be subtracted from the load obligation each year along with a statewide total.

- An indication for each electric supplier of their load pattern (shape) used for power resource planning purposes for the past year and any future expected changes and a summation to indicate a statewide total.

- A power resource screening curve indicating total bus bar cost at relevant capacity factors for resources including renewables.

- A map showing all committed and planned transmission lines 115KV and above plus an estimate of the cost of those lines, as well as an indication of any transmission lines required to meet the load obligation for the state.

Using the information of the items previously mentioned, the report will indicate on a statewide basis a reasonable estimate of the power resource type and timing that would meet the load obligation of the entire state for the 20-year period.

The report will also discuss what renewable type resources electric suppliers are currently using and are planning to use, and any anticipated changes to the technology of these resources.

Any other significant considerations that impact the existing or future power supply resources will also be discussed.

3.0 STATEWIDE LOAD OBLIGATION

3.1 Base Load Forecast

The current combined statewide forecast of non-coincident peak demand is derived by summing the demand forecasts for each individual utility. Each utility supplied a demand forecast and a load and capability table based on the loads having a 50/50 chance of being higher or lower. Over the twenty-year window, the average annual compounded load growth rate for this forecast for the State is 1.8% per year. This growth rate is very similar to the one from two years ago. Thus the estimate of the statewide load growth has not changed over the last couple of years. The growth rate does however vary greatly from utility to utility. The lowest annual compounded growth rate is 0.26% per year and the highest is 2.6% per year. Urban areas continue to show a higher forecasted rate of demand load growth than rural areas.

The Statewide annual energy requirements continue to grow at a slightly higher growth rate than the demand growth rate.

3.2 Nebraska Power System Reserves and Resulting Obligations

3.2.1 Minimum Obligation

In addition to the load requirements of our customers the state utilities must also maintain a 15% minimum reserve margin. This is a requirement of the Mid-Continent Area Power Pool (MAPP). All MAPP Generation Reserve Sharing Pool (GRSP) members must maintain this in order to assist each other in the case of emergencies such as unit outages. By having a reserve sharing "pool", instead of everyone carrying their own reserves to protect them from the loss of the largest unit on their system, the reserve requirement for all members of the "pool' is reduced. So 15% reserve margin is adequate in a pool but on our own it would be higher. This reserve capacity does however amount to significant resource capability over and above the Nebraska load requirement, 743 MW in 2003 and 1,107 MW by 2022.

3.2.2 Planning Obligation

Many of the Nebraska power systems maintain an additional planning reserve margin over and above the minimum required 15%. The amount of planning reserves considered to be adequate varies because of utility differences in size, age, condition and fuel supply of generation resources; population density; abnormal weather, customer demand characteristics; available demand response programs; electric transmission adequacy; unexpected unit retirements due to equipment failure, and system stability among other factors. In total, these additional planning reserves add 223 to 281 MW, or approximately 4 percent, from 2003 through 2022 for Nebraska utilities. This additional risk-based planning criteria in combination with the minimum requirements, establishes a typical planning reserve guideline range of 15 to 20 percent. This range reflects common expectations within the electric utility industry.

Risk-based planning criteria are established over a power resource planning horizon, typically 10 to 20 years in length. This planning horizon length is needed to develop enough lead-time to plan, approve, and build or purchase the required capacity. Depending on the identified circumstances & business environment scenarios that show up within the planning horizon, the resource specifics of the last half of the planning horizon will tend to fluctuate more than the first half simply because of available information & technology updates that may prove more effective than originally conceived or expected at the beginning of the planning horizon.

4.0 EXISTING POWER SUPPLY RESOURCES

As of 2002 the state had a total generating resource capability of 6,220 MW. In addition, there is 505 MW of additional capability under construction that will be in service prior to the summer peak of 2003. This capability includes 451 MW of CT capacity and 54 MW of CC capacity. The specific units are:

Burdick GT #2	34 MW
Burdick GT #3	34 MW
Fremont CT	36 MW
LES SVGS CC	54 MW
LES SVGS CT	27 MW
OPPD Cass Co CT #1	160 MW
OPPD Cass Co CT #2	160 MW
TOTAL	505 MW

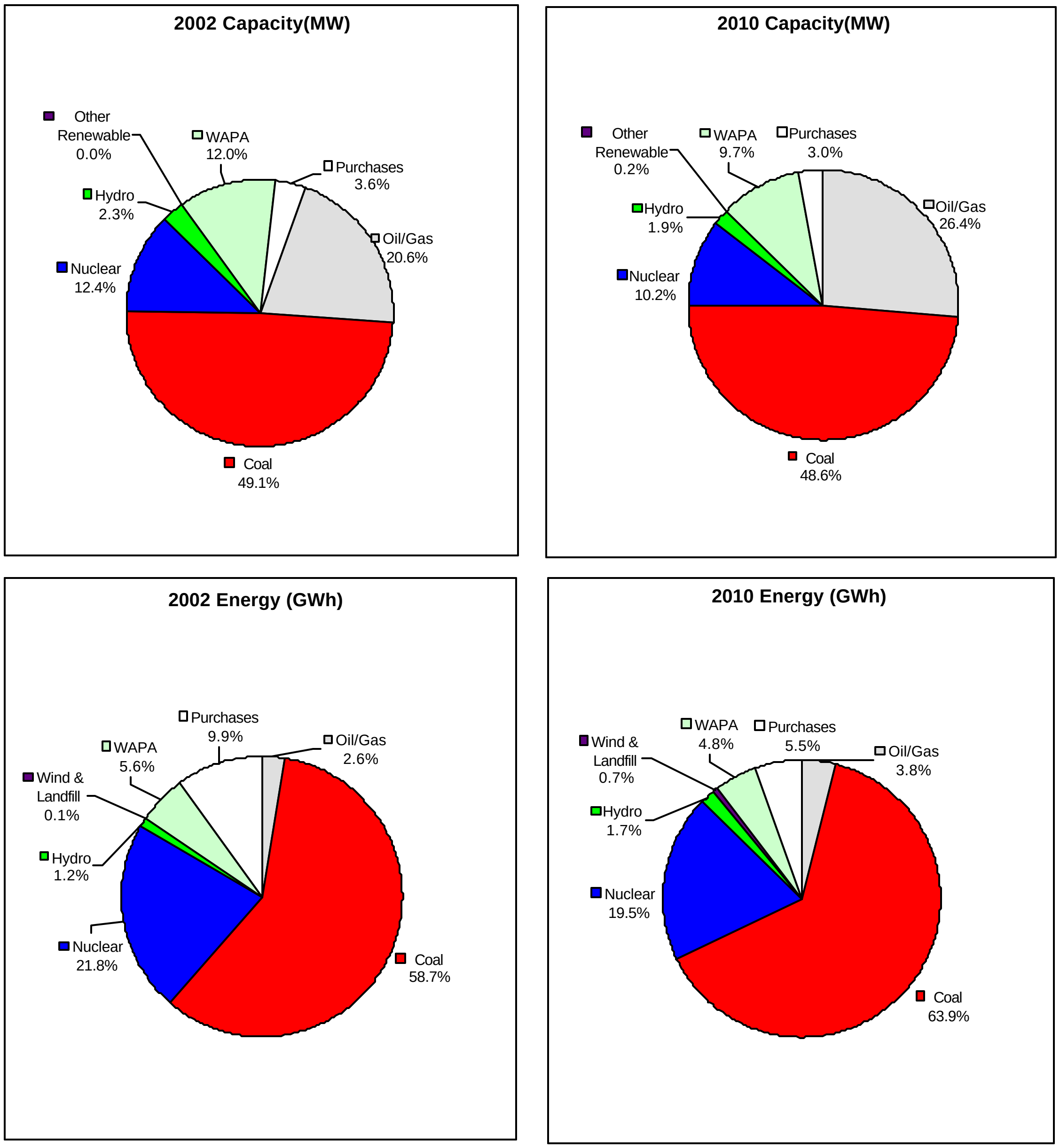
This results in 6,725 MW of existing resources. A complete listing of these existing resources is shown in Appendix C.

4.1 Existing Resource Mix

Exhibit 4.1-1 is a set of pie charts that illustrates the resource mix by fuel type. The left two charts are the resource mix for 2002 actual data and will be discussed below. The right two charts are the 2010 projected data and will be discussed in Section 5.4.

The proportion of total capacity that each fuel type comprised in 2002 is shown in the top left graph. The proportion of total energy is shown in the lower left graph. There are some key points to be taken from the 2002 graphs. Coal resources provide the majority of the capacity and energy in the state in 2002. Coal provided proportionately more energy than capacity as these units are base load resources for Nebraska. The nuclear pieces of the pie are similar to the coal in that they provided proportionately more energy than capacity also because these units are base load resources. WAPA and other hydro resources are the major sources of renewable capacity to the state. The oil and natural gas resources supply significantly more capacity than energy as they are generally peaking units and run for a limited number of hours. They are however required to meet the peak load obligations for the state.

Exhibit 4.1-1
Fuel Source Mix Summary

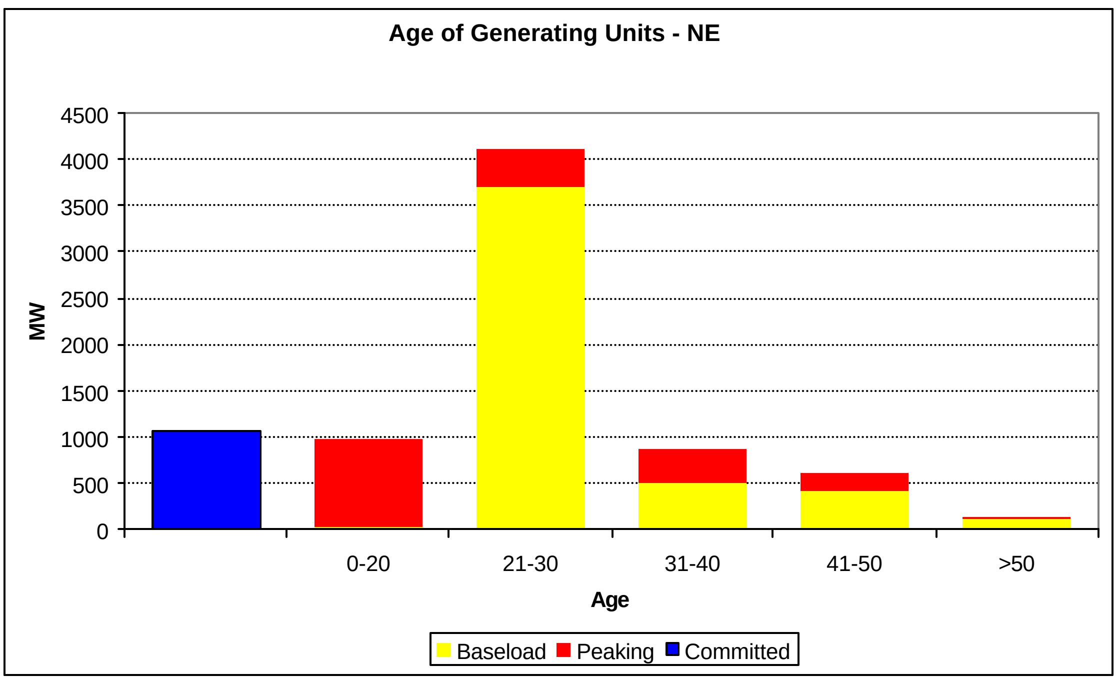


4.2 Ages of Existing Resources

A key consideration in power supply planning is the retirement of existing generating plants. Most new thermal generating plants are built for a normal useful life of 40 to 50 years. Approximately 90% of the existing generation in Nebraska has been in service for more than 20 years, and it will be approaching the end of its original planned useful life by the end of this study period. In addition, there is 771 MW of generation that is more than 40 years old now and will be over 60 years old by the end of the study period. Exhibit 4.2-1 graphically shows the generating resources by age.

Exhibit 4.2-1
Age of Generating Units

		Age					
		0-20	21-30	31-40	41-50	>50	Total
Baseload		41	3,706	505	423	119	4,794
Peaking		942	394	367	198	30	1,932
Existing		983	4,100	872	621	150	6,725
Committed	1064						



With proper operating and maintenance practice, older generating units are capable of continued reliable operations. However, it can be expected that some older generating units will be retired over the study period. As components of older generating units fail, it is increasingly difficult to procure replacement parts and, in some cases, it is not cost effective to repair the generating units.

A part of long-term resource planning could include studies that provide management with some analytical information regarding the long-term use of resources. As the age of units approach 40 years old and greater, and even if they have been well maintained, at some point in the future it may be more economical to retire the units vs. continued operation. This is especially true if new environmental measures are enacted, which may require additional expenditures to allow these units to comply. Long-term engineering studies are typically required to confidently predict: 1) remaining life, and 2) if expenditures above & beyond those expected are needed to maintain the units in their present state. Studies of this type may become more prevalent as units age and resource planning horizons extend.

A main factor that could cause older generating units to be retired is the compliance cost of environmental regulations. Changing interpretations of existing Clean Air Act provisions relating to New Source Review (NSR) as well as new legislation, such as the proposed Clear Skies Act, could force older generating units to install expensive environmental control equipment to remain in service. For some older generating units, installing expensive environmental control equipment could be cost prohibitive relative to the value of keeping the generating unit in service. In some cases, building a new generating plant may be more cost effective than retrofitting an existing plant with the best available retrofit technology. These are economic decisions that Nebraska utilities will be making in the future as circumstances warrant.

Currently, the only expected generating unit retirement in the 20-year planning horizon is the Cooper Nuclear Station (758 MW); due to Nuclear Regulatory Commission (NRC) license expiration. The current expiration date is January 2014. Nebraska Public Power District (NPPD) has not made a decision on whether to apply to extend its operating license at this time.

As planning horizons extend beyond 2022, and other business influences are determined, it is not unreasonable to assume that other generating unit potential retirement dates will be determined as part of a long-term resource plan.

5.0 FUTURE POWER SUPPLY RESOURCES

Power supply resources are categorized as: Committed, Planned, or Studied.

- Committed resources are those units that have been approved by the PRB.

- Planned resources are those units that utilities have authorized expenditures for an architect/engineer, or permitting, but do not have PRB approval.

- Studied resources are those units that are needed to meet the utility's Planned Obligation. These Studied resources are specified based on the theoretically ideal split between baseload, intermediate, and peaking types considering existing and projected needs.

5.1 Committed Power Supply Resources

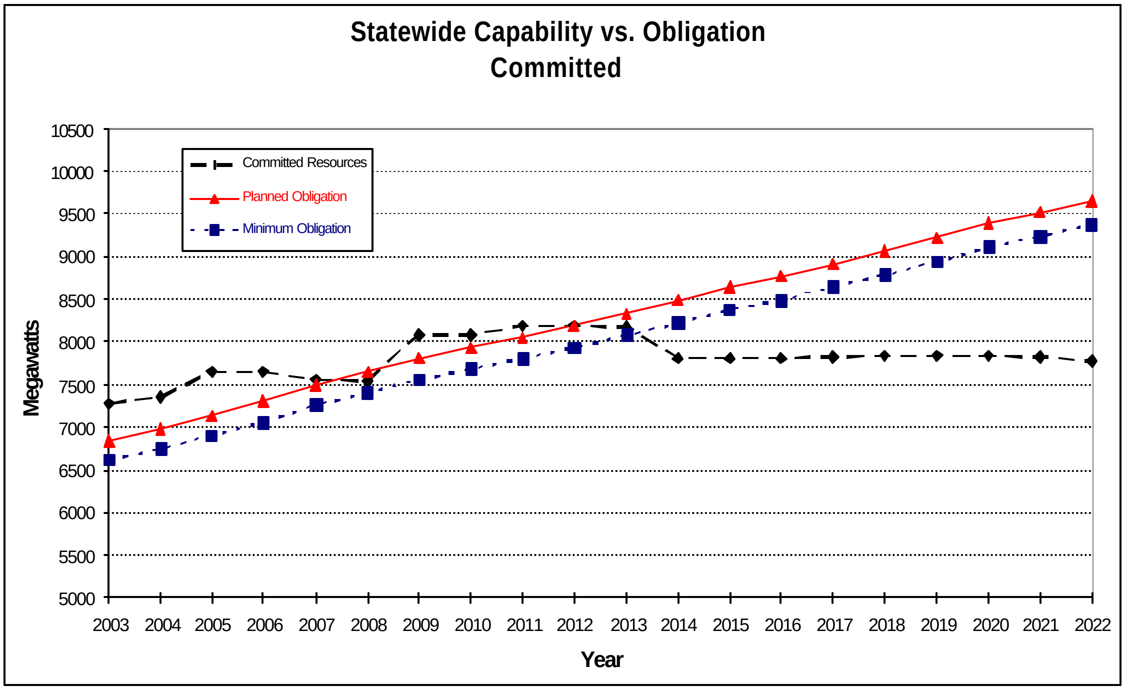
In addition to the 505 MW of new generation expected to be in commercial operation prior to the summer of 2003 there is another 1,064 MW of Committed resources (resources that have been approved by the PRB) that are expected to be constructed in the state. These units are:

LES SVGS CC (Upgrade)	64.6 MW	2004
LES SVGS CT (Upgrade)	18.8 MW	2004
LES SVGS Black Start	1.5 MW	2004
NPPD Beatrice CC	229 MW	2005
LES CB #4	50 MW	2007
MEAN CB #4	50 MW	2007
LES CB #4	50 MW	2009
OPPD Nebraska City #2	600 MW	2009
TOTAL	1,064 MW	

Appendix E contains a table showing the future resource additions and categorizes them by Committed, Planned, and Studied.

Exhibit 5.1-1 shows the statewide load and capability including both Existing and Committed resources. The lower “Minimum Obligation” line is the statewide obligation based on the 50/50 forecast (normal weather) and the minimum 15% reserve requirement of the MAPP reserve sharing pool. The upper obligation line is the combined “Planned Obligation” that the combined Nebraska power systems use. The Load and Capability tables are shown in Appendix B for statewide and individual utilities

Exhibit 5.1-1



Both the Planned Obligation and Minimum Obligation lines increase by about 2,700 MW over this 20 year period. The forecasted loads increase by 2,400 MW over this period.

This exhibit shows that the State is not projected to have a deficit until 2014 for the Minimum Obligation and 2013 for the Planned Obligation with Existing and Committed Resources. This assumes that NPPD does not request the NRC to extend the Cooper Nuclear Station operating license beyond 2013. OPPD has requested the NRC to extend the Fort Calhoun Station operating license from 2013 to 2033.

5.2 Planned Power Supply Resources

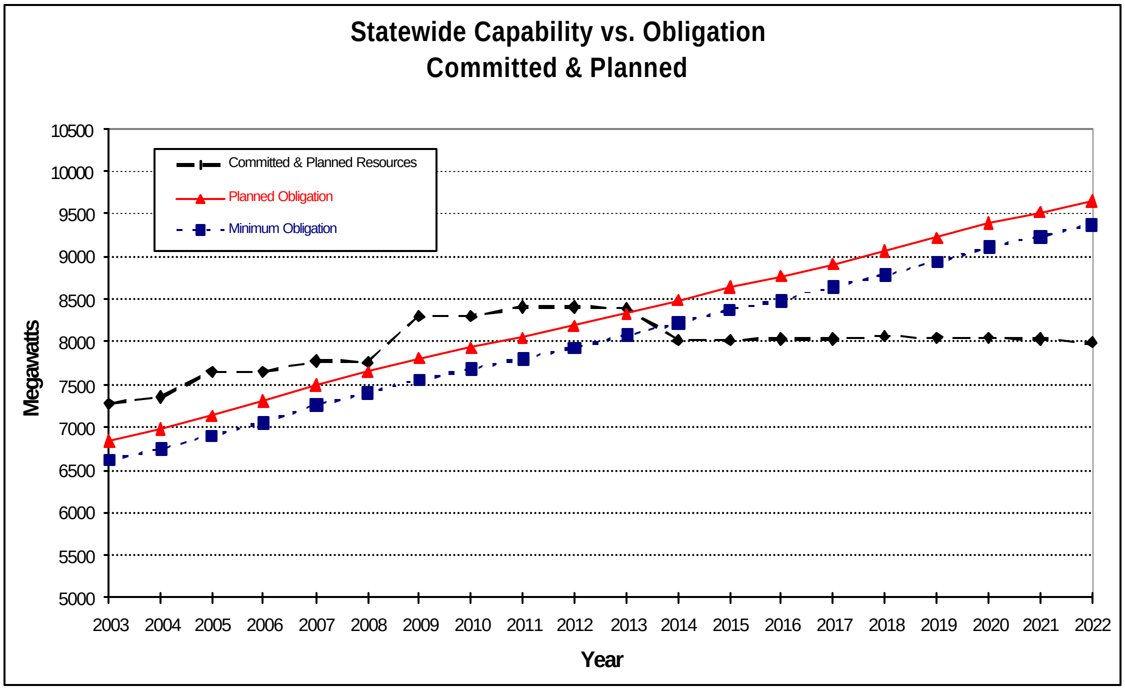
There is one unit that is classified as Planned (units that utilities have authorized expenditures for an architect/engineer, or permitting, but do not have PRB approval) for this report:

Whelan Energy Center #2	220 MW	2007
TOTAL	220 MW	

Eight public power utilities, including seven Nebraska utilities and one South Dakota utility, have been studying the feasibility of constructing a 220 MW pulverized coal-fired generating station adjacent to the existing Whelan Energy Center, near Hastings, Nebraska. None of the project participants have made a firm commitment to participate in the project at this time. Based on the work done to date, including cost projections and permitting activities, this project is a feasible resource to meet Nebraska's baseload needs in the 2007 to 2009 time frame. Significant preliminary work has been completed on the project. Conceptual design has been completed and an application for a Prevention of Significant Deterioration (PSD) construction permit has been submitted to the Nebraska Department of Environmental Quality (NDEQ). It is anticipated that the PSD permit would be issued in the fall of 2003.

Exhibit 5.2-1 shows the statewide load and capability considering Existing, Committed, and Planned resources.

Exhibit 5.2-1



This exhibit shows that the State is not projected to have a deficit until 2014 based on the Planned or Minimum Obligation with Existing, Committed, and Planned resources.

5.3 Studied Power Supply Resources

Resources identified as "Studied" for this report were not based on the traditional method but in a unique way specifically for this statewide plan. For years beyond the point when existing, committed, and planned resources would meet a utility's Planned Obligation, each utility would establish Studied resources in a quantity to meet this deficit gap. These Studied resources are divided based on the theoretically ideal split between base, intermediate, and peaking types considering existing and future needs. The result is a listing for each utility of the ideal mix of future baseload, intermediate and peaking resources for each year following their deficit. The total statewide Studied Power Supply Resources is the sum of all Nebraska utilities for each year and is listed in Appendix E. It is also graphically depicted in Exhibit 5.3-1.

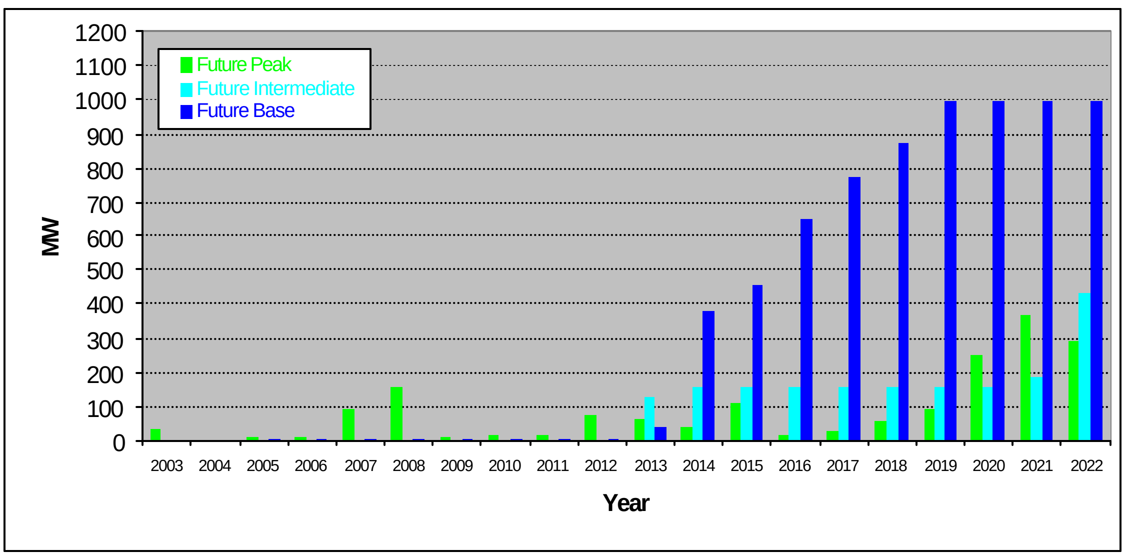
”Studied” power supply resources also refers to evaluations & studies of potential units that could fill the needs identified in the generally classified types noted above (baseload, intermediate, and peaking) where utilities have authorized expenditures for general evaluation and/or future siting study purposes, but do not have local utility Board approval or PRB approval to construct.

Examples of these types of studies include OPPD’s 3 MW Landfill gas addition for 2005, NPPD’s business case evaluation for up to 50 MW of wind generation for operation by fall 2004, and NPPD’s siting & transmission study work for a future potential 400 - 600 MW baseload requirement for the 2014-2022 timeframe.

This summation of Studied resources will provide the basis for the PRB and the state utilities to understand the forecasted future need by year and by resource type. This can be used as a joint planning document and tool for a coordinated long range power supply.

Exhibit 5.3-1

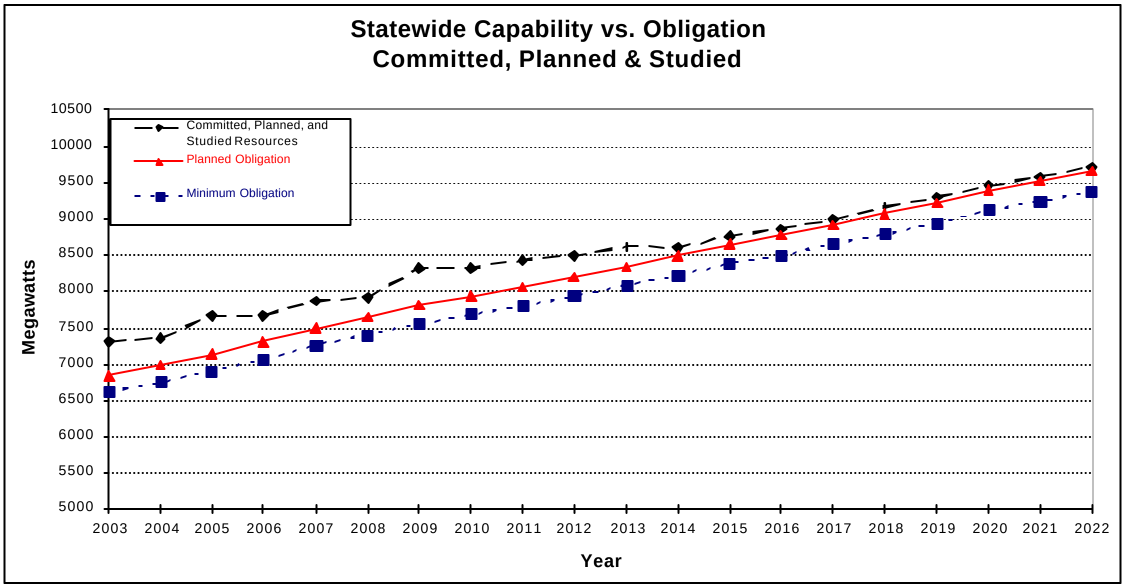
Studied Options by Resource Type



The Studied options include 999 MW of base load capacity, 435 MW of intermediate capacity, and 293 MW of peaking capacity by 2022.

Exhibit 5.3-2 shows the statewide load and capability considering existing, committed, planned, and 1727 MW of studied capacity.

Exhibit 5.3-2



This exhibit shows that the State is not projected to have a deficit for the study period with Existing, Committed, Planned, and Studied resources.

5.4 Projected Resource Mix

Exhibit 4.1-1 shows the 2002 actual and 2010 projected resource mix by fuel type. This exhibit shows the visual perspective as to how the resource mix changes.

Exhibit 5.4-1 tabulates the fuel mix percentages for 2002 and 2010 by capacity and energy and also shows the change in those percentages from 2002 to 2010.

Oil/Gas proportion of fuel mix increases both for capacity and energy. The portion of capacity that is expected to be supplied goes up by 5.8 percentage points (from 20.6% in 2002 to 26.4% in 2010). The portion of energy that is expected to be supplied goes up by 1.2 percentage points (from 2.6% in 2002 to 3.8% in 2010). So the while the % of energy supplied by natural gas or oil is still very small it is expected to increase 50% by 2010.

Coal proportion of fuel mix decreases for capacity and increases for energy. The portion of capacity that is expected to be supplied decreases by 0.5 percentage points (from 49.1% in 2002 to 48.6% in 2010). The portion of energy that is expected to be supplied goes up by 5.2 percentage points (from 58.7% in 2002 to 63.9% in 2010).

Nuclear and WAPA proportion of fuel mix decreases both for capacity and energy. No Nuclear resources are planned so the proportion of the resource mix decreases. Similarly, capacity and energy from WAPA is expected to decrease in actual MW's and MWh's resulting in a smaller proportion being supplied by 2010.

Exhibit 5.4-1
Fuel Source Mix Comparison 2002 & 2010

Capacity Mix(%)

	2002	2010	Change
Oil/Gas	20.6%	26.4%	5.8%
Coal	49.1%	48.6%	-0.5%
Nuclear	12.4%	10.2%	-2.2%
WAPA	12.0%	9.7%	-2.3%
Hydro	2.3%	1.9%	-0.4%
Other Renewable	0.0%	0.2%	0.1%
Purchases	3.6%	3.0%	-0.6%
	100.0%	100.0%	0.0%

Energy Mix(%)

	2002	2010	Change
Oil/Gas	2.6%	3.8%	1.2%
Coal	58.7%	63.9%	5.2%
Nuclear	21.8%	19.5%	-2.3%
WAPA	5.6%	4.8%	-0.8%
Hydro	1.2%	1.7%	0.5%
Other Renewable	0.1%	0.7%	0.6%
Purchases	9.9%	5.5%	-4.4%
	100.0%	100.0%	0.0%

Hydro proportion of fuel mix decreases for capacity but increases for energy. That is because 2002 was a very poor water year so projecting normal water in 2010 causes an increase in proportion of energy supplied from the state's hydro resources.

Other renewable proportion of fuel mix increases both for capacity and energy. The portion of energy that is expected to be supplied goes up by 0.6 percentage points (from 0.1% in 2002 to 0.7% in 2010). So the while the percentage of energy supplied by other renewable resources is very small it is expected to be 5 to 6 times more than 2002. Purchases are expected to decrease as internal Nebraska resources are developed.

6.0 RENEWABLE RESOURCES

Generally, renewable options within the State of Nebraska are more expensive than other power supply alternatives but may provide value-added applications in a power resource portfolio. Renewable technologies when compared to conventional power resources are typically considered a customer-driven option. Many renewable technologies are not dispatchable. They can supply energy but cannot be counted on for capacity purposes unless a second resource, such as a peaking unit, is available to "firm-up" the renewable supply. However, renewable technologies can be of additional value as a hedge against potential environmental cost adders or can produce additional revenue through the salability of an environmental benefit such as "Green Tag Program".

"Green Tags" or "certificates", also known as Renewable Energy Credits (RECs), and Tradable Renewable Certificates (TRCs) are built on the premise that renewable energy generators actually make two saleable products: electricity and the environmental benefit of avoided emissions, called environmental attributes. For example, a wind turbine producing 750 kW of electrical power approximately 35% of the year or 2,300,000 kWh is making two products—the energy itself, which can be sold into the local electrical grid at the prevailing price, and the environmental attributes of that generation. Green tags allow for a direct transaction between a green energy supplier and another power supplier or an end-user reducing economic transaction costs. A wind developer could, for example, build a wind farm in Nebraska and sell the environmental attributes (or Green Tags) to an electric power supplier in Alabama that wishes to be environmentally responsible and perhaps market itself as such. Green tags can make the green energy generation market efficient, because generation can be sited wherever it is most advantageous (for resource, siting, and transmission needs) while the environmental benefit—captured in the green tag—can be sold where resources are not so easy to come by. Likely candidates include power suppliers and institutional buyers, such as federal and state facilities, or large industrial customers.

Business case development applying reasonable assumptions and sound analytical techniques is a reasonable method of ensuring the best value-based application of renewables in a power resource portfolio. Equipment field-testing, revenue stream proposal development, market data, resource portfolio impact modeling, and sound consumer research all combine to validate the best long-term application of renewable resources.

OPPD has built a Landfill Gas to Energy (LFGTE) facility at the Elk City Douglas County landfill. The LFGTE facility contains four internal combustion engine/generators. Each generator has a nominal rating of 800 kW. OPPD owns the LFGTE facility, and Waste Management, Inc. operates it. Current plans include an expansion to double the size of this facility by 2005.

The four existing wind projects in Nebraska are at Kimball, Springview, Valley, and in north Lincoln. They utilize different wind units and lie in different wind regimes. Some of this data will be useful in developing trade-offs between larger projects in windy regions versus smaller projects requiring lower integration and electric transmission cost near the loads but having less wind.

MEAN has developed a 10.5 MW (nameplate) project located near Kimball on the Western Interconnection. This project was in commercial operation by October 2002 and consists of seven 1.5 MW wind turbines located 3 miles northwest of Kimball with an expected annual capacity factor of 35%. This is currently the single largest wind facility in Nebraska and was developed due to some of MEAN's customers desire to have green power, but was not developed under a subsidized renewable energy program of some kind.

The Springview project is a multi-partner distributed generation project and consists of two 750 kW wind turbine units. OPPD has one wind turbine in Valley with a nameplate rating of 660 kW. LES has two wind turbines in north Lincoln with a total nameplate rating of 1.3 MW. In addition, NPPD is currently evaluating the business case for up to 50 MW of wind generation for operation by fall 2004.

Renewable Energy Programs within the State have shown that Nebraska consumers are interested in developing renewable projects; however, only on a limited basis when customer funding is required on a voluntary basis. For example, LES has roughly a 2% participation rate in its Renewable Energy Program, which at this point is highest participation rate within the State. OPPD also has a Renewable Energy Program with about 1% participation. Tri-State started a Renewable Resource Power Service program in 1999. This program makes green power available to all 44 Members of Tri-State for sales to their members. NPPD is currently pursuing the possibility of additional consumer information survey work to be completed this year.

Recently the Governor has asked for additional business plan development work focused on how Nebraska can be a leader in applying wind energy options to benefit Nebraskans. This business plan could affect other power supply expectations as well.

In addition to generating projects, NPA members along with some state agencies participated in and completed a wind-monitoring program throughout the state. Data is available as to the wind availability in various parts of Nebraska.

7.0 RESEARCH AND CONSERVATION

7.1 Research

Typical research projects include the use of renewable resources in Nebraska for test cases, demonstration projects, and joint developments where joint benefits can be obtained or for environmental cost risk hedging. The projects that have been utilized within the state are co-firing with bio-fuels and coal on a test basis, demonstration wind projects at Springview and in Lincoln developed under a Renewable Energy Program, a joint methane plant at a landfill with OPPD, and an OPPD joint wind project at Valley. These projects have been and are being used to develop valuable insights into how these renewable options interact with the transmission, distribution, and generation system of local utilities and to identify their costs. NPPD plans to participate in a Deliberative Polling process for assessing customers' level of interest in renewable energy in 2003.

In addition to these local projects, larger Nebraska utilities are members of the Electric Power Research Institute (EPRI), which has a broad based research effort in renewable projects.

The review and development of Biopower projects is being encouraged through the Biopower Steering Committee created by the Nebraska Legislature in 1999. The committee is charged with identifying opportunities to generate electricity from Nebraska's biomass resources, especially in the rural parts of the state. The committee's membership includes key stakeholders whose collaboration will effectively facilitate successful biomass power demonstration in Nebraska. With appropriate funding, the committee will, for example, be able to identify relevant, feasible technology, and analyze Nebraska's biomass resources as possible feedstocks and may support a demonstration project. NPPD has had on-going communications with developers pursuing more cost-effective methods of managing these waste streams and with confinement operators. Most process owners and/or confinement operators would prefer not to own and operate generation equipment since this is not their area of expertise by choice. NPPD is currently evaluating business cases where NPPD would be the electrical generator owner/operator in cost-effective processes that provide methane for generation and process heat.

7.2 Demand-Side Management Resources

DSM options are implemented to affect changes in load characteristics of utilities. They can utilize direct control of equipment, involve rate incentives, or involve utility interaction or all three. They can be characterized as peak clipping, valley filling, or combinations thereof. The affect of DSM options are generally thought to be beneficial to all customers in the utility and not just those customers participating in the program. This is accomplished by creating the potential to delay supply-side resource additions or optimize resource utilization through load shape modifications.

The existing DSM programs in the state are anticipated to continue but will undoubtedly be modified in the future.

The largest component in the Nebraska DSM is load shifting, primarily based on the control of irrigation pumping load. (Load shifting is accomplished when on peak load is shifted to off peak periods). Taking 2005 as a test year, irrigation load control is expected to represent 63% of the total DSM in the state.

The peak clipping category of DSM programs is also very large in the state. Curtailable load is the largest peak clipping category and amounts to 20% of the DSM and generally affects the larger customers.

The remaining 17% of 2005 DSM is made up of direct load control for smaller customers such as residential, efficient motor programs, rate incentive programs, distributed generation programs, real time pricing and educational programs. Appendix D summarizes the estimated effects of DSM by 2005 for the State.

The existing DSM programs continually undergo review and modifications. Incremental additions to existing DSM programs are expected to include more emphasis on pricing incentives such as real time pricing, time of use rates, and expansion of curtailable load programs. It is estimated that by 2005 a little more than 600 MW of additional resources would be needed to meet peak demands without these DSM programs.

In discussing future DSM options it should be remembered that programs in place at one utility may be under study by another. For example, some utilities currently have air conditioner load control programs while others are investigating it. DSM options that continue to have a higher priority for investigation by utilities within the state are:

- air conditioner load control programs
- curtailable load programs
- water heating load control programs
- shade trees
- distributed generation options
- refrigerator trade-in
- time of use rates
- efficient lighting
- real time pricing

7.3 Distributed Generation

One of the trends in the electric utility industry is toward distributed generation. "Distributing" small generators near customer loads has advantages similar to DSM but it can also be viewed as locational or customer-specific supply side generation. These small generators can range in size from several kW's at a customer location or several MW at large customer sites or at utility load serving substations.

New technologies, or improvements in cost and performance of existing options, could make distributed generators more cost-competitive. The installed capital cost of residential fuel cells and micro-turbines are both expected to drop dramatically in the future. These units are generally powered by natural gas and would be subject to the cost, availability, and deliverability of that fuel.

The economic viability of distributed generators is dependent upon interconnection standardization as well as the potential incremental costs associated with the fuel source (both operational and safety related).

Fuel cells can be sized for residential customers (3 kW) or for large commercial and industrial customers (200 kW). Micro-turbines (40 - 80 kW) are also a new technology being piloted in Nebraska (OPPD, NPPD, and Tri-State). Distributed generation is not entirely new. Some customers have had standby and emergency diesel generators for many years.

Distributed generation can offer a number of benefits to the electric utility and the customer. For the electric utility, the possible benefits of distributed generation may include deferred transmission and distribution system upgrades, lower line losses, reduced need for peaking capacity, and improved system reliability. For example, if an electric utility needed additional generation to serve the load in a particular area, a generator could be installed at a local substation. For customer-owned distributed generation systems, the possible advantages could include lower electric utility cost (including potential pass through savings from utility transmission and distribution expenses), and increased reliability. Distributed generators may enable customers to generate reliable, high-quality power for sensitive digital equipment. Electric utilities were not originally designed to furnish uninterruptible power. Dependence on electricity has grown to the extent that, for many customers, power quality (including reliability), is a primary driver for installing distributed generation.

It is generally believed that distributed generation will continue to develop in the next several years and very often will be driven by other customer concerns than just the cost of electric supply.

7.4 Cogeneration

In some large industrial applications, the customer's total energy bill includes the cost of electricity provided its supplier as well as the internally-generated cost of steam for the production process. A cogeneration facility could be located on customer property where the electrical output from such facility could tie directly to the transmission system of the electrical supplier and the steam-cycle portion of the facility could tie directly to customer for the production process.
The industrial customer would continue to receive electrical power from its supplier and could also receive steam from the cogeneration facility owner. NPPD and some of its customers have participated in several preliminary

discussions with various interested large industrial customers primarily as an economic development tool, but no projects are currently beyond the concept stage.

8.0 LOAD PATTERNS OF SUPPLIERS

8.1 Basic Definitions

When a customer flips a light switch and the light comes on, the electrical power required to turn on the bulb is considered “load".

The electrical power that serves the load is nearly instantaneously created at a power plant and transmitted through transmission & distribution lines to serve that particular customer.

This same electrical power that serves a given load over a specified time period (usually an hour) is called “energy," and the physical unit of energy (in large quantities) is called a Megawatt-hour (MWh).

The physical capability to provide this “energy” on an instantaneous basis is called “capacity," and the physical unit of capacity (in large quantities) is called a Megawatt (MW).

So “energy” is different from “capacity” because “energy” is over a greater, more useful and easier measured unit of time, such as a single hour.

By charting the energy used each hour in a year in chronological order (Hour 1, January 1 through Hour 24, December 31), a “load pattern” or “load shape” is created, and because each utility has different types of customers, the annual load shape of each utility is slightly different. An example of a chronologically ordered hourly energy chart showing hourly energy for a summer week in 2002 is provided in Exhibit 8.3-1.

If this “load shape” chart is sorted from highest load to lowest then a “load duration” curve is created. This “load duration” curve shows that the short duration, peak loads, are considered the highest loads, and the long duration, base loads, are shown as the lower loads.

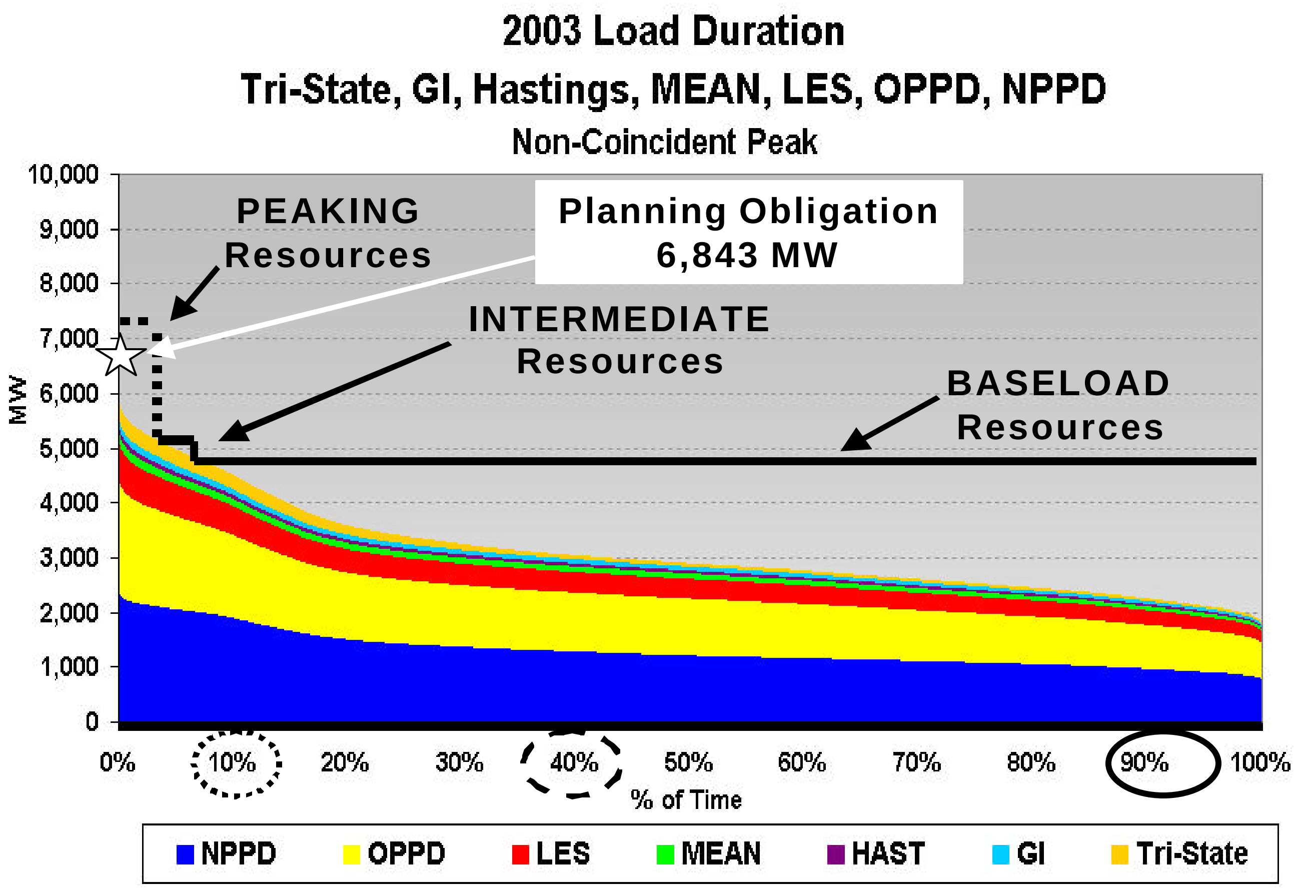
Loads shown between the peak & base loads are considered intermediate loads. An example of a “load duration” curve for 2003 is provided in Exhibit 8.2-1.

The advantage of a “load duration” curve is that it helps visualize a cost-effective mix of resources (or “capacity”) by matching resource types to the expected load duration and matching the percentage of time the load must be served.

8.2 Nebraska Statewide Load Duration Curves & Matching Capacity Resources

Exhibit 8.2-1, below, shows the expected 2003 load duration curve for the indicated Nebraska utilities, sorted in descending order to create a load duration curve. Super-imposed on that load duration curve is a representation of the existing 2003 capacity resources that were utilized to meet that load obligation. The term "Non-Coincident Peak" means that the calculations were performed by sorting each utility's loads in descending order, then summing. Planning Obligation is described in Section 3.2.2.

Exhibit 8.2-1

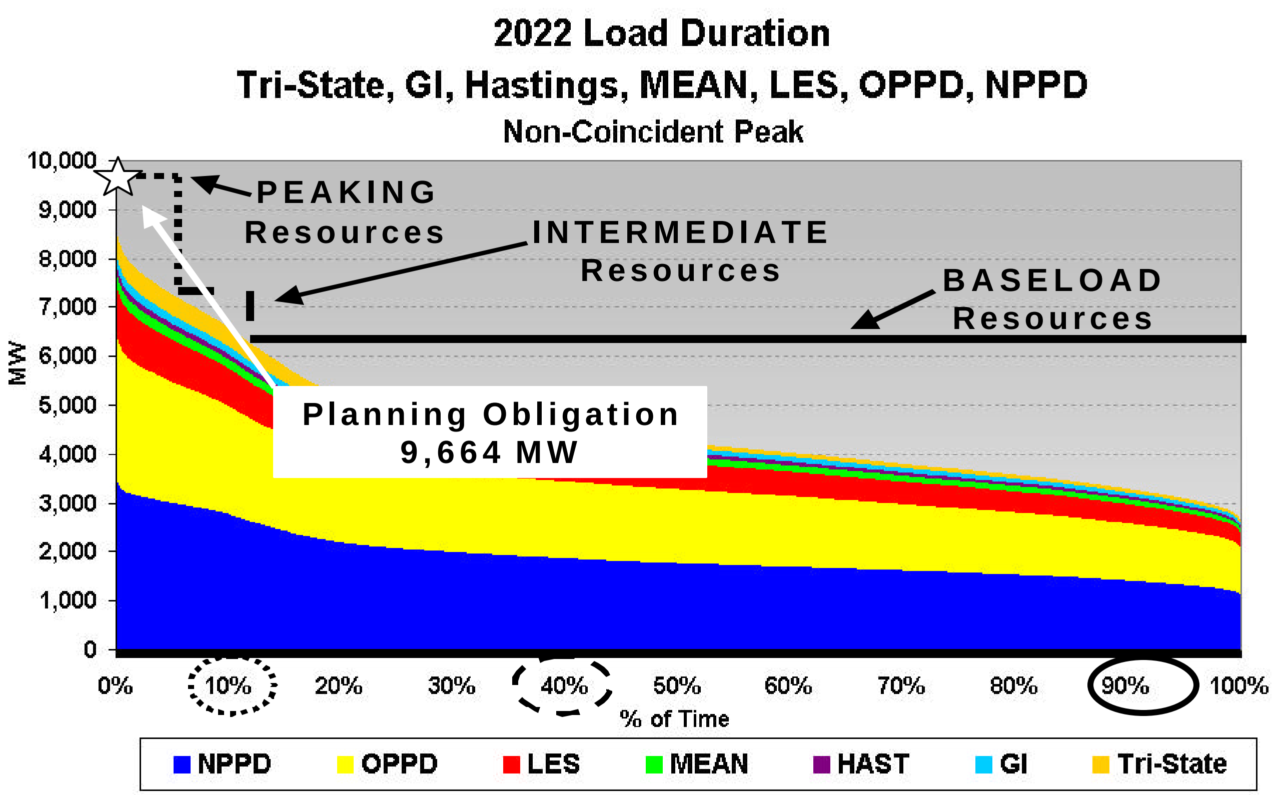


	Peaking (MW)	Intermediate (MW)	Baseload (MW)	TOTAL (MW)
Calculated "Existing" 2003 Generating Capability (owned) TOTAL	1,843	252	4,660	6,755
	27%	4%	69%	100%
Net Resource Capability TOTAL (+ Purchases - Sales)	2,168	252	4,880	7,300
	30%	3%	67%	100%

Exhibit 8.2-1, above, demonstrates the adequacy and effective matching of Nebraska capacity resources to the required load obligation while maintaining solid reserves in case of unexpected unit outages. Resource diversity and risk sharing is also accomplished through various purchases & sales while effectively meeting the expected load obligation (the second line on the table above summarizes the net effect of these purchases & sales). The surplus energy at certain hours is sold to the market, and the revenue produced helps offset costs and produces downward pressure on customer rates. It should be noted that there is less operational flexibility with mostly baseload & peaking resources, since baseload is "on" most of the time, and peaking resources are expensive to run in the higher duration percentages.

Exhibit 8.2-2 below shows the expected 2022 load duration curve and 2022 Existing, Committed, Planned, and Studied Resources.

Exhibit 8.2-2



	Peaking (MW)	Intermediate (MW)	Baseload (MW)	TOTAL (MW)
Calculated "Existing, Comitted, Planned, Studied" 2022 Generating Capability (owned) TOTAL	**2,157**	**980**	**5,791**	**8,928**
	24%	**11%**	**65%**	**100%**
Net Resource Capability TOTAL (+ Purchases - Sales)	**2,510**	**980**	**6,223**	**9,713**
	26%	**10%**	**64%**	**100%**

The chart above demonstrates that growth in load is matched with growth in resources along with increased diversity in purchases & sales. There is a definite capacity resource shift from baseload and peaking to more intermediate type resources. This is projected to provide more effective operational resource flexibility while matching an increasing statewide load duration expectation. A solid reserve margin in case of unexpected unit outages is still maintained while closing the gap in the intermediate load duration range.

8.3 Nebraska Statewide Load Shapes – Typical Week Basis (2002)

Exhibit 8.3-1 below shows the actual 2002 hourly loads for the Nebraska utilities for a typical week during the summer of 2002.

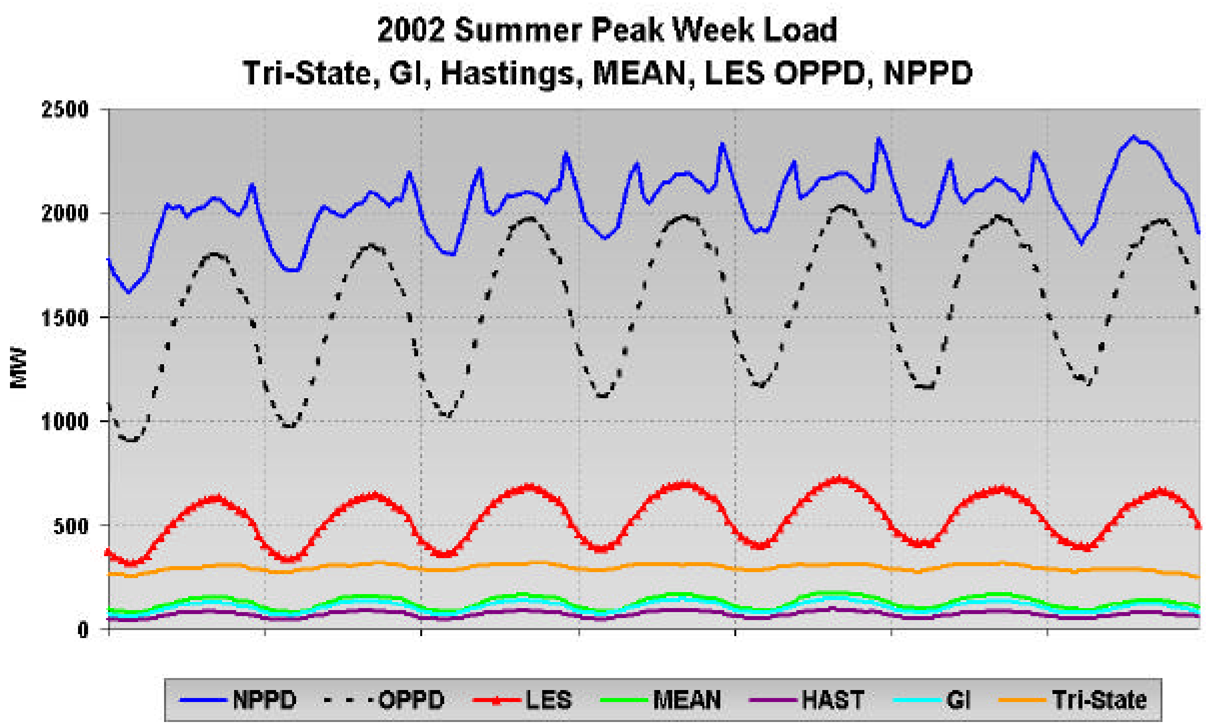


Exhibit 8.3-1

This chart demonstrates the diversity in the noted Nebraska utilities loads by the "spikes" that show more fluctuation in higher demands for one utility, while other utility demands are smoother. A utility may experience a double peak situation during different times of the day, while others are more single peak. Load reduction strategies for utilities that serve more rural or irrigation loads that shift high demands to off-peak hours will show substantial variation from other utilities that serve more metropolitan loads and have different kinds of load reduction strategies. This supports the need for operational flexibility associated with capacity resources in order to effectively meet varying load patterns, and diversity between rural & metropolitan loads across the state of Nebraska.

9.0 POWER RESOURCE SCREENING CURVES

9.1 Discussion of Use of Curves

Power resources can be categorized into three different types of options: Baseload, Intermediate, and Peaking. Based on the number of hours of operation (or capacity factor) a given resource is expected to operate, the three types of resources could demonstrate enough flexibility to operate as shown below:

–Peaking Units:	**0 - 25% of the year**
–Intermediate Units:	**15 - 75% of the year**
–Baseload Units:	**60 - 100% of the year**

Some forms of generation, such as nuclear and large fossil steam units, are well suited for Baseload operation because of their relatively low operating cost, even though their installed capital cost may be higher. Conversely, other forms of generation that have a lower installed capital cost, such as Combustion Turbines, generally have a higher operating cost (principally due to fuel and heat rate), thus making them appropriate to utilize as Peaking units. An example of an Intermediate unit would be a Combined Cycle, which has the flexibility to run at lower or higher capacity factors.

Based on actual operating experience of Nebraska utilities and the previously described load patterns, the various power resource types in Nebraska typically operate:

–Peaking Units:	**0 - 10% of the year**
–Intermediate Units:	**15 - 40% of the year**
–Baseload Units:	**70 - 95% of the year**

9.2 Screening Curves

Capital cost, operating cost, and performance data for supply-side resources expected to be available during the twenty year study period of 2003-2022 are shown in Appendix F. These options include conventional methods of power supply, emerging technologies, storage technologies , and renewables. Each option was screened on a levelized busbar cost basis to determine the least-cost baseload, intermediate, and peaking options at various capacity factors.

The screening curve is used to determine the relative cost of each option. Those options with the highest construction and operating costs relative to other supply-side options with the same operational mode are eliminated. The screening curve analysis utilized is a plot of the levelized busbar costs versus capacity factor for each technology. A sample curve for seven of the least expensive technologies is shown in Exhibit 9.2-1. Appendix F also contains a graphical representation of the costs of each option by component: capital, operating, and fuel costs for 1%, 24%, and 85% capacity factors.

While screening curves are useful for comparing options they can not be utilized as the sole means for making resource selections. That is because they do not contain some information that is necessary to making final resource selection.

Some of the items that cannot be evaluated with screening curves are:

Dispatchability

Timing

Effects on dispatch of other units.

Forced Outages

Planned Maintenance outages

Coincidence of generation with load

Existing resource mix

So while they provide considerable insight for comparison of like resources, they are only one tool to be utilized in the resource planning process.

The least cost options based on the screening curves are shown below:

Peaking Units (0-10% Capacity Factor):

Combustion Turbines
Combined Cycle

Intermediate (15% -40% Capacity Factor):

Combined Cycle
Pulverized Coal
Integrated Gasification Combined Cycle
Fluidized Bed

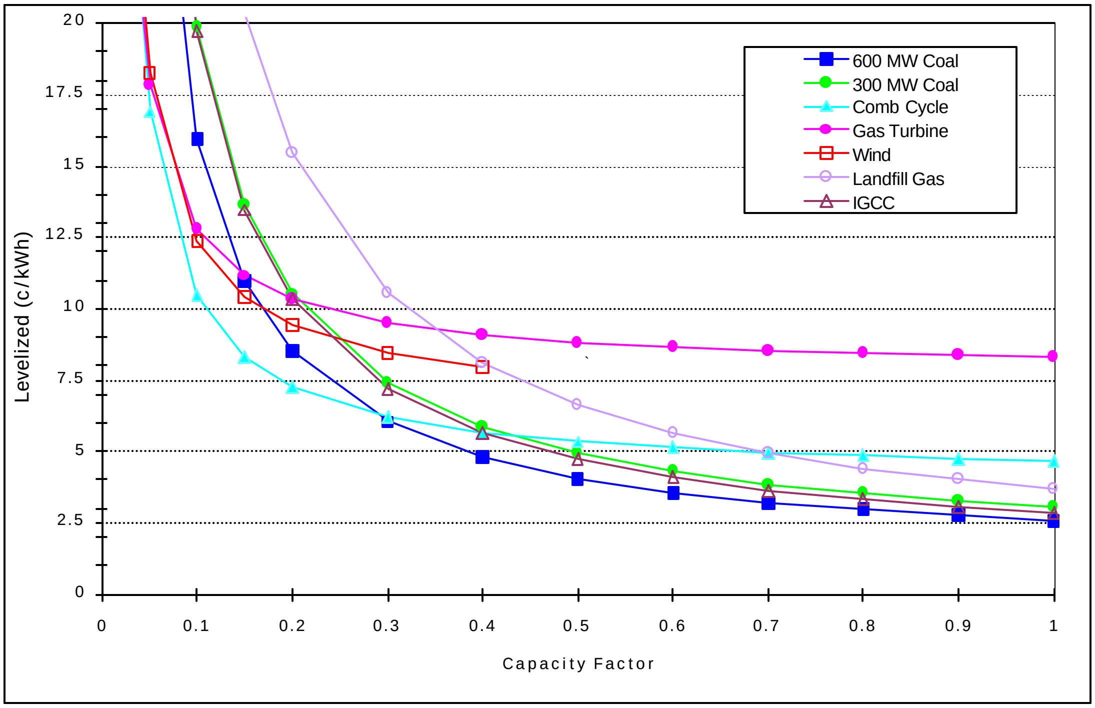
Baseload (70% -95% Capacity Factor):

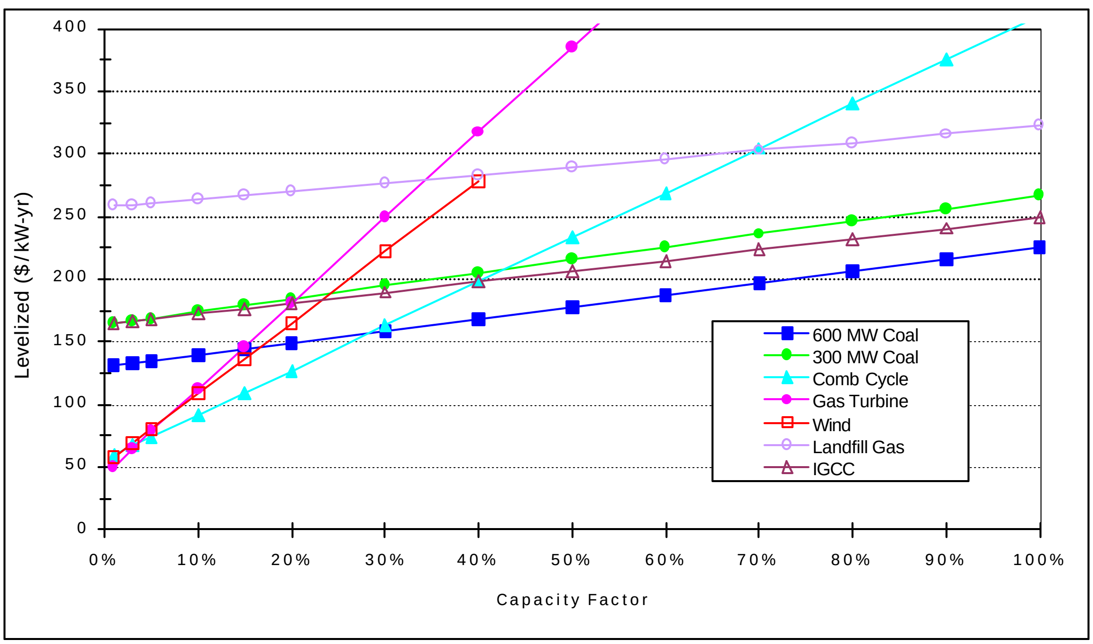
Pulverized Coal
Integrated Gasification Combined Cycle
Fluidized Bed
Landfill Gas

Renewables:

Wind Turbines
Landfill Gas

Exhibit 9.2-1
Screening Curves





10.0 TRANSMISSION REQUIREMENTS

10.1 Nebraska Subregional Transmission Plan

The Nebraska Subregional Planning Group (Nebraska SPG) was formed under the MAPP Transmission Planning Subcommittee (TPSC) in 1997. The primary objective of the Nebraska SPG is to develop a coordinated ten-year transmission plan for the Nebraska subregion on a biennial basis. The Nebraska Subregional Transmission Plan was published in April of 2002 to accommodate the projected needs from 2002–2011 and is considered the coordinated transmission plan for the Nebraska subregion.

The Nebraska Subregional Transmission Plan included a comprehensive analysis of the local area load serving capability for each of the Nebraska SPG members. The loadflow analysis focused on the five and ten year planning horizon with detailed evaluations of the 2006 and 2011 Summer Peak Load models. All of the current committed future transmission and generation facilities in the Nebraska subregion were included in the base models. The Nebraska SPG also included some future year generation expansion plans which are still in the preliminary planning stages. Detailed results of the contingency analysis, discussion of operating procedures, and future transmission facility plans are included in the final report. The detailed listing of all planned transmission lines and facility upgrades for the Nebraska subregion is shown in Form 1 of Appendix 1 from the Nebraska Subregional Transmission Plan (2002–2011).

The Nebraska SPG has included discussion of transmission planning activities associated with various resources identified in the NPA Report. For generation sites which are committed, there are detailed transmission plans developed and approved. Preliminary screening studies have also been performed for many of the proposed future sites, but detailed analysis is still required to develop robust transmission plans for the future generation development and until firm commitments for capacity and specific sites are selected, the transmission plans are only preliminary. Based on the need to accommodate an additional 1727 MW of new intermediate and baseload generation, significant future transmission additions could be required in the state of Nebraska.

The following subsections provide a summarized overview of the future plans and activities involving the NPA members of the Nebraska SPG.

Nebraska Public Power District

Nebraska Public Power District (NPPD) owns and operates 4240 miles of transmission lines in the state of Nebraska. This is comprised of 895 miles of 345 kV, 683 miles of 230 kV and 2662 miles of 115 kV facilities. The NPPD control area encompasses a significant portion of the state of Nebraska. The NPPD system is characterized by summer peak irrigation loads, extreme seasonal load level variations, western Nebraska stability limitations, and four regional constrained transmission interfaces. The Nebraska Subregional Transmission Plan addresses the 2002–2011 summer peak load serving needs for the NPPD control area. NPPD has also performed system impact studies and developed transmission facility plans to address numerous potential and committed resource additions which affect the NPPD system.

Broken Bow Area Transmission Study

NPPD has experienced significant summer peak load growth in the Broken Bow area. The Broken Bow Area Transmission Study was performed to address the deficiencies in this area. The planned facility additions involve the development of the Crooked Creek 230/115 kV substation with the addition of a 230/115 kV transformer and the construction of 40 miles of 115 kV transmission line from Crooked Creek to Broken Bow. This project is scheduled to be in-service by the summer of 2003.

Beatrice Combined Cycle Power Plant

NPPD is constructing a new combined-cycle generating facility near Beatrice, Nebraska. The Beatrice Power Station Generation Accreditation Study was completed to document the transmission plan to accommodate the accreditation of the Beatrice Power Station at 250 MW. This study was recently approved by the MAPP Design Review Subcommittee. The Beatrice Power Station (BPS) is planned as two 80 MW combustion turbines and one 90 MW steam turbine and is scheduled for a June 2005 in-service date. The BPS generating units will tie into the new Beatrice Plant 115 kV substation. The Beatrice Plant 115kV substation will tap into the existing Beatrice–Sheldon 115 kV and Beatrice–Clatonia–Sheldon 115 kV transmission lines. The Beatrice Plant substation will be configured as a breaker and a half with four 115 kV lines utilized for generator outlet capacity. Three of the 115 kV outlet transmission lines will be re-conductored and the fourth line will be upgraded. The Beatrice–Steinauer–Humboldt 115 kV transmission line will also be upgraded. There will also be upgrades to terminal equipment at the Sheldon, Beatrice, Steinauer, Humboldt and Sterling substations.

Wind Generation

NPPD is currently evaluating the integration of up to 50 MW of wind generation in north central Nebraska. Transmission site screening studies have been performed and system impact / facilities studies are currently in progress to define the transmission plan required for integration of up to 50 MW of wind generation into the NPPD transmission system.

Grand Island Burdick GT #2 & GT #3

NPPD recently performed the Grand Island Electric Department Burdick GT-2 and Burdick GT-3 Generation Accreditation Study to address the transmission system accreditation for these new resources. Two 40 MW combustion turbines were recently added at the Grand Island Burdick Station. The results of the study demonstrated required upgrades to four 115 kV transmission facilities within or adjacent to the Grand Island 115 kV system. The study was approved by the MAPP Design Review Subcommittee and all of the facility upgrades have been completed recently.

Whelan Energy Center # 2

At the request of MEAN, NPPD performed a System Impact Study and Transmission Site Screening Analysis for the proposed 250 MW coal-fired plant at Hastings. This study identified high-level transmission system limitations associated with the integration of a new 250 MW generator located at the existing Hastings Energy Center site. This loadflow study focused on voltage, thermal loading and constrained path impact issues. The study also evaluated potential solutions and developed a recommended transmission plan required to address the transmission system impacts of the proposed plant.

Lincoln Electric System

The Lincoln Electric System (LES) Service Area covers approximately 190 square miles within Lancaster County. The LES system comprises 50 miles of 345 kV, 12 miles of 161 kV, and 159 miles of 115 kV lines. The system also includes three 345/115 kV tie transformers located at the Wagener and NW68th & Holdrege 345 kV substations.

Current LES resource development involves constructing the Salt Valley Generating Station (SVGS). The SVGS will be connected into the transmission system by tying to the existing 70th & Bluff to Waverly 115 kV line. The 70th & Bluff end of the 115 kV line to 84th & Fletcher will be moved to the SVGS providing for three 115 kV outlet lines.

LES has signed a joint owner agreement for a new power plant proposed by MidAmerican Energy Company. The plant, a nominal 790 MW super-critical coal-fired unit planned for Council Bluffs, IA, will include a total LES share of 100 MW (50 MW in 2007 and an additional 50 MW in 2009). MidAmerican expects to begin commercial operation of the Council Bluffs Energy Center Unit # 4 (CBEC-4) in June 2007. The CBEC-4 project will include the following major transmission system additions with the projects located within Nebraska shown in bold type:

- Grimes 345/161 kV substation and autotransformer
- CBEC – Grimes 345 kV line
- **Sub 1206 – Sub 1217 161 kV line**
- **CBEC – Sub 1206 161 kV**
- CBEC 345/161 kV transformer #2
- Rebuild CBEC – Avoca 161 kV line
- **Terminal equipment replacements on Cooper South facilities**

LES also plans to rebuild the existing 5.5-mile Rokeby–20th & Pioneers 115 kV line. The new line will use bundled conductors and have a normal conductor rating of approximately 373 MVA. The rebuilt line will go into in-service during the 2004/2005 winter.

A new 3.5-mile radial 115 kV line will supply the NW12th & Arbor Substation from the existing 19th & Alvo Substation. The line and substation have an in-service date of fall 2003. Future transmission plans have an 11.0-mile 115 kV line being constructed from the NW12th & Arbor Substation to the NW63rd & Holdrege Substation. The in-service date for this line is 2005.

A new 5.0-mile radial 115 kV line will supply the 40th & Rokeby Substation from the existing Rokeby Substation. The line and substation have an in-service date of May 2006.

Omaha Public Power District

The Omaha Public Power District (OPPD) serves more than 300,000 customer-owners spread over a 5000 square mile service area in southeastern Nebraska. The major metropolitan area served is the City of Omaha and its surrounding suburbs; the balance of the service area is predominantly rural. OPPD owns and operates 330 miles of 345 kV transmission lines, 402 miles of 161 kV transmission lines and 482 miles of 69 kV transmission lines. OPPD also owns and operates five 345/161 kV autotransformers and twelve 161/69 kV autotransformers.

The following transmission projects are planned in and around the Omaha metropolitan area:

- A new 161 kV transmission line from MEC Council Bluff Energy Center to OPPD Sub 1206 and a new 161 kV transmission line from Sub 1206 to Sub 1217 will be in service by 2005. These lines were identified during a joint planning study for CBEC-4.

- A new 345/161 kV autotransformer is currently planned for installation at Sub 3454/1254. This autotransformer will be in service by 2004.

OPPD is also beginning the process of evaluating the transmission impacts of Nebraska City Unit #2. After the participants are finalized, OPPD plans to coordinate a joint study determining what transmission modifications are necessary for plant output.

Fremont Area

The loss of internal Fremont generation can cause overloads of the two 69 kV ties (OPPD Sub 976 to Fremont Sub D and the NPPD 115/69 kV). Numerous contingencies in and around the Fremont area, including loss of either of the two 69 kV ties or the loss of Fremont generation, can result in voltage drops below allowable levels. OPPD will coordinate a joint study with the city of Fremont and NPPD to investigate the severity of the problems and determine any transmission requirements.

345/161 kV Autotransformers

With the majority of the new generation in the region being added at 345 kV the need for new 345/161 kV autotransformers in the Omaha area is evident. OPPD is currently planning on installing one new 345/161 kV autotransformer in West Omaha. OPPD may need to install a fifth 345/161 kV autotransformer in the Omaha metro area sometime after 2010.

Sub 1211 – Sub 1299 & Sub 1211 – Sub 1220

There are two 161 kV circuits that connect the North Omaha Generating Station to downtown Omaha. In the 2011 Summer Peak model, failure of either of the two circuits overloads the other. OPPD is currently evaluating options to remedy this problem.

Municipal Energy Agency of Nebraska

MEAN is a network transmission customer of NPPD. In general, transmission improvements necessary to serve MEAN load in the MAPP area are planned and constructed by NPPD. MEAN's loads are included in NPPD's transmission planning analyses and studies. MEAN is also in the planning phases of a 220 MW coal-fired generating project in the Hastings, NE area. There are seven other utilities that are participating in the planning phases of the project. If the project is feasible, it is scheduled to be in service by the summer of 2007. MEAN is working with NPPD to study transmission improvements that may be necessary to integrate this project as a network resource to serve MEAN loads in the MAPP area.

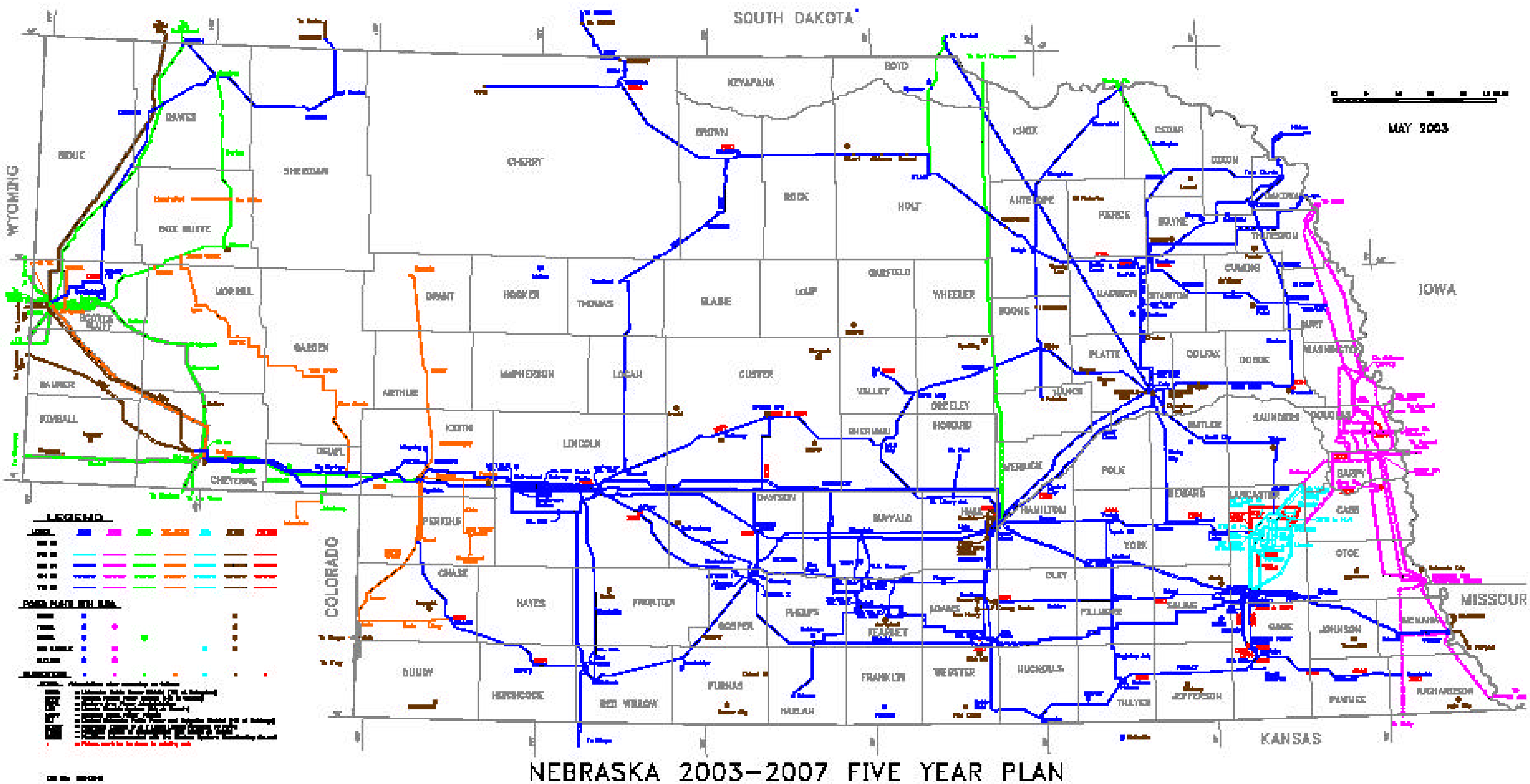
Tri-State G & T Association

Tri-State recently completed the construction of the Elsie-Red Willow Creek-Blackwood Creek 115 kV line to address local load serving needs in the Western Nebraska region. Tri-State is considering a plan to extend this 115 kV line into the Enders area in the future. As far as future year planning analysis, the NPPD section of the Nebraska SPG Final Report addresses all of the critical contingencies in the NETS area for the 2006 and 2011 Summer Peak periods.

Joint Iowa - Nebraska SPG Study Efforts

The Nebraska SPG participated in the Joint Iowa - Nebraska SPG which analyzed the regional constrained paths in the Missouri River Corridor. The Joint Iowa - Nebraska SPG focused on developing transmission plans to address these constraints and increasing the MAPP to Southwest Power Pool (SPP) regional transfer capability. The details of the analysis and results of this joint study effort are contained in the *Joint Iowa – Nebraska Subregional Planning Group / Missouri River Corridor Transfer Capability Study / Report To The MAPP Transmission Planning Subcommittee.*

Exhibit 10.1-1
Nebraska 2003-2007 Five Year Plan



APPENDIX A

Nebraska Utilities Joint Efforts

NPA Reports

1981	Statewide Generation Planning Study
1981	Energy Conservation Load Management Renewable, R & D, Cogeneration
1982	Statewide Transmission Planning Study
1982	Energy Conservation Load Management Renewable, R & D, Cogeneration
1983	Energy Conservation Load Management Renewable, R & D, Cogeneration
1984	Statewide Generation & Transmission Planning Study
1984	Energy Conservation Load Management Renewable, R & D, Cogeneration
1985	Load Forecasting Methodologies and Procedures Used by Nebraska Utilities
1985	Energy Conservation Load Management Renewable, R & D, Cogeneration
1986	Statewide Resource & Transmission Planning Study
1987	Small Wind Generation Study
1988	Review of Public Power Industry Structure
1988	Energy Conservation Load Management Renewable, R & D, Cogeneration
1988	Advantages of Load Factor Improvements
1991	Electromagnetic Fields - Index of Information Sources And Resource Documents
1991	Statewide Resource & Transmission Planning Study
1991	Energy Conservation Load Management Renewable, R & D, Cogeneration
1994	Statewide Wind Resource Preliminary Economic Study
1995	Biomass to Electric Energy
1995	Renewable Energy Generation Update Report
1996	Statewide Integrated Resource Planning Coordination Report
1997	Summary Report for Integrated Resource Planning Public Forum
1997	Statewide Integrated Resource Planning Summary
1999	Nebraska Wind Energy Site Data Study
2001	Statewide Integrated Resource Planning Summary

In addition an annual load and capability report for the state has been prepared since 1985.

2) Other Joint Activity

NPPD-OPPD Nuclear Operating Company Feasibility Study

NPPD and OPPD have formed a task force to determine the feasibility of and the potential efficiencies and performance improvements that could have been obtained through the joint and cooperative operation and maintenance of Cooper Nuclear Station and Fort Calhoun Nuclear Station. The vision of the study was to create a Nebraska Operating Company to maintain or enhance safety while improving operational and financial performance. At this time the NPPD and OPPD Boards' of Directors have chosen not to pursue this option.

Wind Generation Project - Springview, Nebraska

NPPD, LES, MEAN, the City of Grand Island, the City of Auburn, KBR Rural Public Power District, the Department of Energy, and EPRI participate in a wind generation project. Two 750 kW wind turbines were installed in the fall of 1998 near Springview, Nebraska.

Nebraska Joint Resource Planning

During the early part of 1999, LES, OPPD, and NPPD met four times over an approximately two-month period to investigate preliminary ideas about a joint power supply resource to be installed in 2003 or thereafter. Information was shared about the needs and options being considered by the individual utilities. Preliminary detailed production runs were individually performed for a gas-fired combined cycle plant. Each utility modeled an equal 1/3 share of the plant.

Generally, the results were fairly market dependent with the combined cycle being dispatched some of the time to sell into the non-firm energy market.

No further joint work is planned for the immediate future for the following reasons:

(1) For LES and NPPD the future shares to be taken from Cooper Nuclear Station after 2003 were not known, which considerably affected a joint combined cycle decision.

(2) The utilities all generally had different capacity requirement dates.

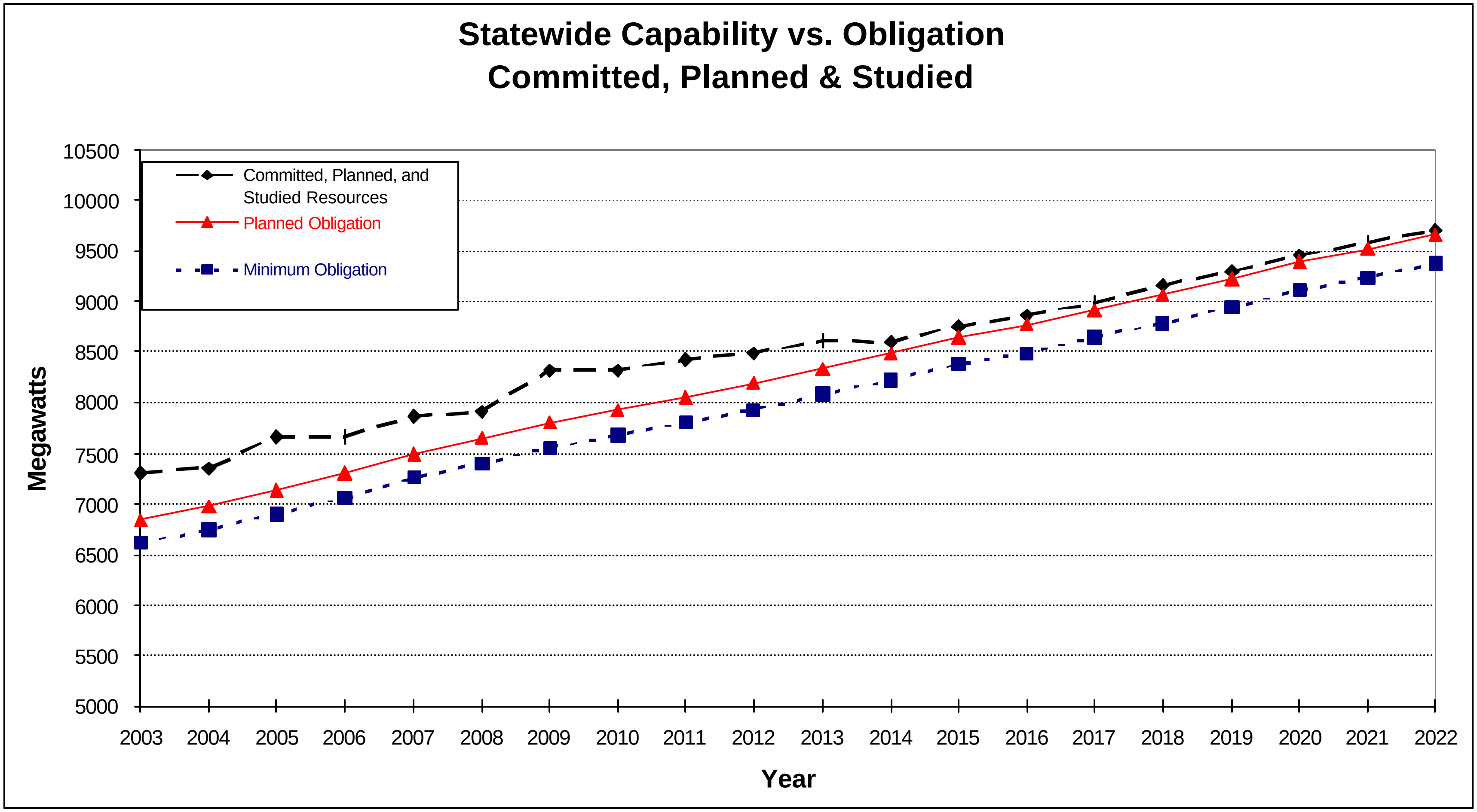
Whelan Energy Center Unit #2

Since 2001, eight public power utilities, including seven Nebraska utilities and one South Dakota utility, have been studying the feasibility of constructing a 220 MW pulverized coal-fired generating station adjacent to the existing Whelan Energy Center, near Hastings, Nebraska. None of the project participants have made a firm commitment to participate in the project at this time. Based on the work done to date, including cost projections and permitting activities, this project is a feasible resource to meet Nebraska's baseload needs in the 2007 to 2009 time frame.

Significant preliminary work had been completed on the project. Conceptual design has been completed and an application for a Prevention of Significant Deterioration (PSD) construction permit has been submitted to the Nebraska Department of Environmental Quality (NDEQ). It is anticipated that the PSD permit would be issued in the fall of 2003.

APPENDIX B

Statewide and Individual Utility Load & Capability Data


Statewide Capability vs. Obligation
Committed, Planned & Studied
Committed, Planned, and Studied Resources
Planned Obligation
Minimum Obligation
Megawatts
10500
10000
9500
9000
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8000
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2021
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Year

NEBRASKA STATEWIDE

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1 Seasonal System Demand	5,875	5,992	6,124	6,263	6,433	6,562	6,694	6,795	6,908	7,020	7,147	7,273	7,411	7,509	7,635	7,760	7,898	8,040	8,157	8,276
2 Annual System Demand	5,875	5,993	6,124	6,263	6,433	6,562	6,694	6,795	6,908	7,020	7,147	7,273	7,411	7,510	7,635	7,761	7,898	8,041	8,158	8,276
3 Firm Purchases - Total	1,058	1,061	1,061	1,061	1,064	1,065	1,074	1,074	1,071	1,073	1,072	1,075	1,080	1,080	1,081	1,083	1,086	1,086	1,089	1,090
4 Firm Sales - Total	44	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10
5 Seasonal Adjusted Net Demand (1-3+4)	4,861	4,941	5,072	5,211	5,378	5,506	5,629	5,731	5,846	5,957	6,084	6,208	6,341	6,439	6,563	6,687	6,823	6,964	7,078	7,196
6 Annual Adjusted Net Demand (2-3+4)	4,861	4,941	5,072	5,211	5,378	5,506	5,629	5,731	5,846	5,957	6,084	6,208	6,341	6,440	6,563	6,687	6,822	6,964	7,079	7,196
7 Net Generating Capability (owned)	6,755	6,816	7,046	7,051	7,455	7,525	8,041	8,043	8,046	8,111	8,244	7,843	7,985	8,086	8,218	8,385	8,530	8,681	8,799	8,928
8 Participation Purchase -Total	385	265	266	267	248	248	428	428	428	428	428	428	428	428	428	428	428	428	428	428
9 Participation Sales -Total	854	774	706	705	895	913	1,213	1,209	1,106	1,117	1,114	732	728	725	721	733	729	725	722	723
10 Adjusted Net Capability (7+8-9)	6,286	6,307	6,606	6,613	6,807	6,859	7,256	7,261	7,367	7,421	7,557	7,539	7,684	7,789	7,925	8,080	8,229	8,383	8,505	8,633
11 Net Reserve Capacity Obligation (6 x 0.15)	743	756	776	797	823	843	862	878	896	913	933	952	973	988	1,008	1,027	1,048	1,070	1,088	1,107
12 Total Firm Capacity Obligation (5+11)	5,604	5,697	5,847	6,008	6,201	6,349	6,491	6,609	6,742	6,870	7,017	7,160	7,314	7,428	7,571	7,714	7,871	8,034	8,166	8,302
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	681	610	759	604	606	511	764	652	625	550	540	378	370	361	354	366	358	349	339	331
14 Surplus or Deficit (-) Capacity @ Planned Obligation	457	386	520	363	362	264	516	400	372	295	281	117	106	95	85	94	83	73	60	49

NEBRASKA STATEWIDE

Seasonal Purchases and Sales in Megawatts

Summer Conditions (May 1 to October 31)

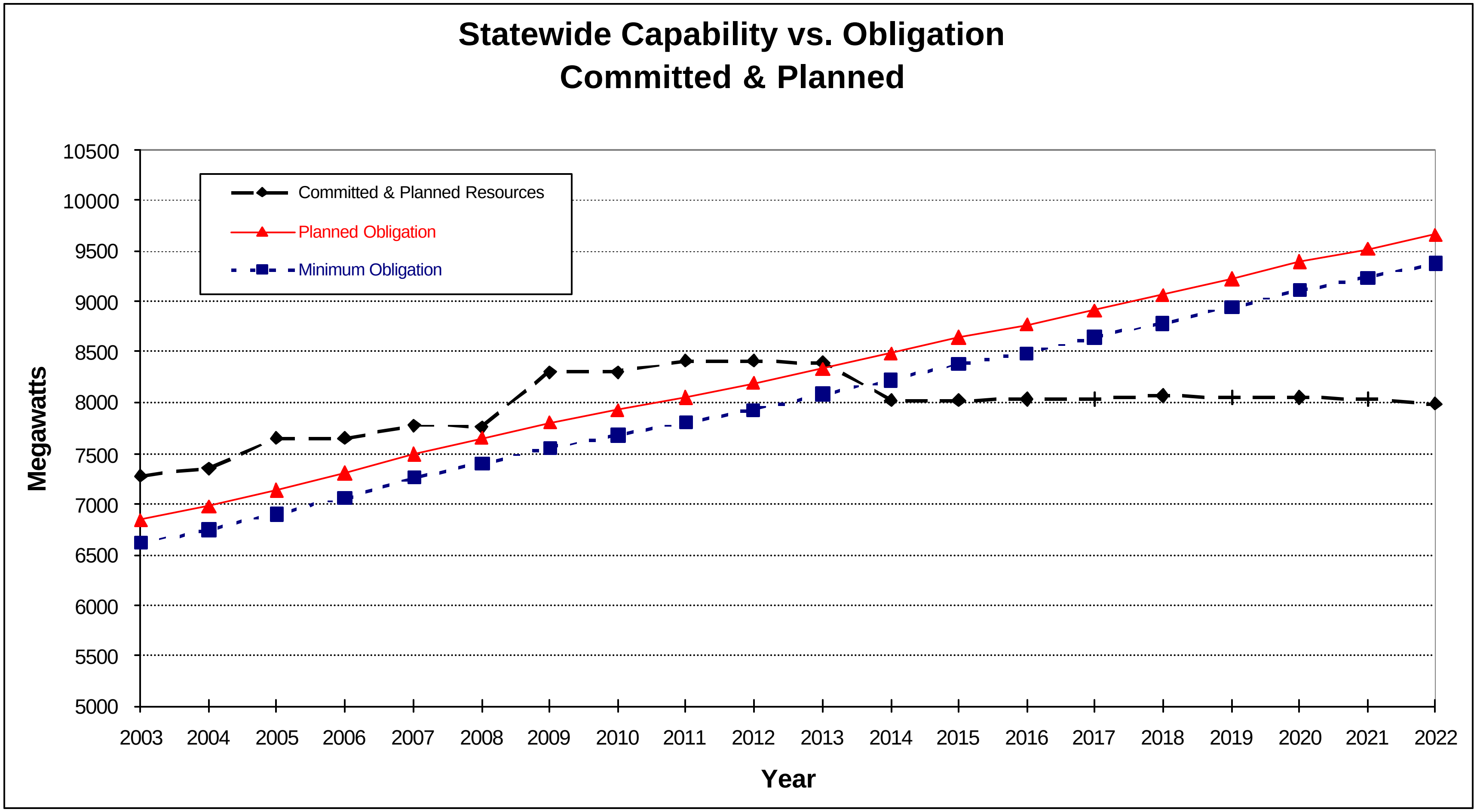
Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
Auburn (WAPA)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Falls City (WAPA)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Fremont (WAPA)	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	4	4	4	4
Grand Island (WAPA)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Hastings (WAPA)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LES (WAPA)	127	127	127	126	126	126	126	126	124	124	124	124	124	124	124	124	124	124	124	124
MEAN (WAPA)	51	51	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Nebraska City (WAPA)	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
NPPD	451	451	451	447	447	447	447	447	442	442	442	442	442	442	442	442	442	442	442	442
OPPD (WAPA)	82	82	82	81	81	81	81	81	80	80	80	80	80	80	80	80	80	80	80	80
TRI-STATE	305	308	310	317	320	321	329	330	335	337	336	338	343	343	345	347	349	350	352	353
Wahoo (WAPA)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Firm Purchases	1058	1061	1061	1061	1064	1066	1074	1074	1071	1073	1072	1075	1080	1080	1081	1083	1086	1086	1089	1090
Firm Sales																				
OPPD Sale to NSP	35	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPPD Wholesale Customers	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10
Total Firm Sales	44	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10

NEBRASKA STATEWIDE

Seasonal Purchases and Sales in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Participation Purchases																				
Falls City	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fremont	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Grand Island	0	0	0	0	15	15	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Hastings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LES	272	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
MEAN	77	88	89	90	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Nebraska City	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD	5	0	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150
OPPD	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	385	265	266	267	248	248	428	428	428	428	428	428	428	428	428	428	428	428	428	428
Participation Sales																				
Falls City	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Fremont	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Grand Island	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hastings	20	15	5	5	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
LES	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
MEAN	0	0	0	0	0	19	16	12	9	20	17	14	10	7	3	15	11	7	4	5
Nebraska City	5	5	4	3	3	2	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NPPD	782	707	656	656	656	656	656	656	556	556	556	177	177	177	177	177	177	177	177	177
OPPD	11	11	5	5	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Total Participation Sales	854	774	706	705	895	913	1213	1209	1106	1117	1114	732	728	725	721	733	729	725	722	723


Statewide Capability vs. Obligation
Committed & Planned
Committed & Planned Resources
Planned Obligation
Minimum Obligation
Megawatts
10500
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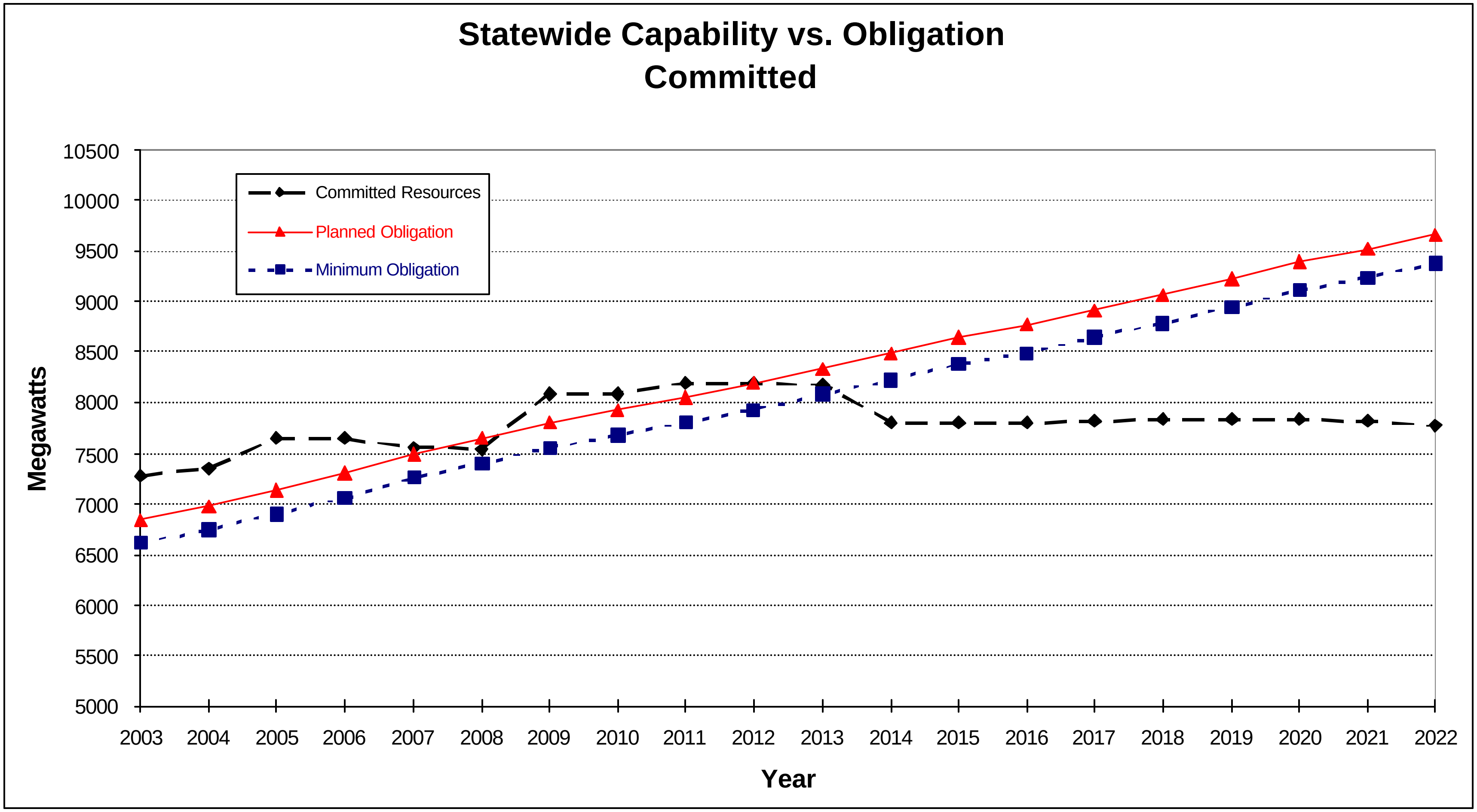
2022
Year

NEBRASKA STATEWIDE

Committed & Planned Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1 Seasonal System Demand	5,875	5,992	6,124	6,263	6,433	6,562	6,694	6,795	6,908	7,020	7,147	7,273	7,411	7,509	7,635	7,760	7,898	8,040	8,157	8,276
2 Annual System Demand	5,875	5,993	6,124	6,263	6,433	6,562	6,694	6,795	6,908	7,020	7,147	7,273	7,411	7,510	7,635	7,761	7,898	8,041	8,158	8,276
3 Firm Purchases - Total	1,058	1,061	1,061	1,061	1,064	1,065	1,074	1,074	1,071	1,073	1,072	1,075	1,080	1,080	1,081	1,083	1,086	1,086	1,089	1,090
4 Firm Sales - Total	44	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10
5 Seasonal Adjusted Net Demand (1-3+4)	4,861	4,941	5,072	5,211	5,378	5,506	5,629	5,731	5,846	5,957	6,084	6,208	6,341	6,439	6,563	6,687	6,823	6,964	7,078	7,196
6 Annual Adjusted Net Demand (2-3+4)	4,861	4,941	5,072	5,211	5,378	5,506	5,629	5,731	5,846	5,957	6,084	6,208	6,341	6,440	6,563	6,687	6,822	6,964	7,079	7,196
7 Net Generating Capability (owned)	6,725	6,816	7,033	7,038	7,363	7,363	8,028	8,028	8,028	8,035	8,020	7,262	7,260	7,259	7,259	7,294	7,276	7,276	7,249	7,201
8 Participation Purchase -Total	385	265	266	267	248	248	428	428	428	428	428	428	428	428	428	428	428	428	428	428
9 Participation Sales -Total	854	774	706	705	895	913	1,213	1,209	1,106	1,117	1,114	732	728	725	721	733	729	725	722	723
10 Adjusted Net Capability (7+8-9)	6,256	6,307	6,593	6,600	6,715	6,697	7,243	7,246	7,349	7,345	7,333	6,958	6,959	6,962	6,966	6,989	6,975	6,978	6,955	6,906
11 Net Reserve Capacity Obligation (6 x 0.15)	743	755	775	796	821	840	858	874	891	908	927	945	965	980	998	1,017	1,037	1,059	1,076	1,093
12 Total Firm Capacity Obligation (5+11)	5,604	5,696	5,847	6,007	6,199	6,346	6,487	6,605	6,737	6,865	7,011	7,153	7,306	7,419	7,561	7,704	7,860	8,023	8,154	8,289
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	652	611	746	593	516	351	756	641	612	480	322	-195	-347	-457	-595	-715	-885	-1,045	-1,199	-1,383
14 Surplus or Deficit (-) Capacity @ Planned Obligation	427	388	508	352	272	105	508	389	359	225	63	-457	-611	-723	-864	-987	-1,160	-1,322	-1,478	-1,664


Statewide Capability vs. Obligation
Committed
Committed Resources
Planned Obligation
Minimum Obligation
Megawatts
10500
10000
9500
9000
8500
8000
7500
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6500
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Year

NEBRASKA STATEWIDE

Committed Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1 Seasonal System Demand	5,875	5,992	6,124	6,263	6,433	6,562	6,694	6,795	6,908	7,020	7,147	7,273	7,411	7,509	7,635	7,760	7,898	8,040	8,157	8,276
2 Annual System Demand	5,875	5,993	6,124	6,263	6,433	6,562	6,694	6,795	6,908	7,020	7,147	7,273	7,411	7,510	7,635	7,761	7,898	8,041	8,158	8,276
3 Firm Purchases - Total	1,058	1,061	1,061	1,061	1,064	1,065	1,074	1,074	1,071	1,073	1,072	1,075	1,080	1,080	1,081	1,083	1,086	1,086	1,089	1,090
4 Firm Sales - Total	44	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10
5 Seasonal Adjusted Net Demand (1-3+4)	4,861	4,941	5,072	5,211	5,378	5,506	5,629	5,731	5,846	5,957	6,084	6,208	6,341	6,439	6,563	6,687	6,823	6,964	7,078	7,196
6 Annual Adjusted Net Demand (2-3+4)	4,861	4,941	5,072	5,211	5,378	5,506	5,629	5,731	5,846	5,957	6,084	6,208	6,341	6,440	6,563	6,687	6,822	6,964	7,079	7,196
7 Net Generating Capability (owned)	6,725	6,816	7,033	7,038	7,143	7,143	7,808	7,808	7,808	7,815	7,800	7,042	7,040	7,039	7,039	7,074	7,056	7,056	7,029	6,981
8 Participation Purchase -Total	385	265	266	267	248	248	428	428	428	428	428	428	428	428	428	428	428	428	428	428
9 Participation Sales -Total	854	774	706	705	895	913	1,213	1,209	1,106	1,117	1,114	732	728	725	721	733	729	725	722	723
10 Adjusted Net Capability (7+8-9)	6,256	6,307	6,593	6,600	6,495	6,477	7,023	7,026	7,129	7,125	7,113	6,738	6,739	6,742	6,746	6,769	6,755	6,758	6,735	6,686
11 Net Reserve Capacity Obligation (6 x 0.15)	743	755	775	796	821	840	858	874	891	908	927	945	965	980	998	1,017	1,037	1,059	1,076	1,093
12 Total Firm Capacity Obligation (5+11)	5,604	5,696	5,847	6,007	6,199	6,346	6,487	6,605	6,737	6,865	7,011	7,153	7,306	7,419	7,561	7,704	7,860	8,023	8,154	8,289
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	652	611	746	593	296	131	536	421	392	260	102	-415	-567	-677	-815	-935	-1,105	-1,265	-1,419	-1,603
14 Surplus or Deficit (-) Capacity @ Planned Obligation	427	388	508	352	52	-115	288	169	139	5	-157	-677	-831	-943	-1,084	-1,207	-1,380	-1,542	-1,698	-1,884

Peak Demand Growth
(2003 to 2022)

	Rate
Falls City Utilities	0.26%
Fremont Department of Utilities	2.50%
Grand Island Utilities	2.45%
Hastings Utilities	2.58%
Lincoln Electric System	2.00%
Municipal Energy Agency Of Nebraska	1.50%
Nebraska City Utilities	1.40%
Nebraska Public Power District	1.51%
Omaha Public Power District	2.14%
Other Municipals (Plainview & Wisner)	0%
Tri-State G&T*	0.77%
STATEWIDE	1.82%

* Only Nebraska's load.

Auburn Board of Public Works

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1 Seasonal System Demand	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2 Annual System Demand	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
3 Firm Purchases - Total	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Net Demand (1-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Annual Adjusted Net Demand (2-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Net Generating Capability (owned)																				
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Adjusted Net Capability (7+8-9)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Net Reserve Capacity Obligation (6 x 0.15)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Total Firm Capacity Obligation (5+11)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Surplus or Deficit (-)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Auburn Board of Public Works

Seasonal Purchases and Sales in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Firm	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total Firm Purchases	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Firm Sales																				
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Falls City Utilities

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15	15	15	15	15	0.26%
2 Annual System Demand	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15	15	15	15	15	
3 Firm Purchases - Total	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	11	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12	12	12	12	12	
6 Annual Adjusted Net Demand (2-3+4)	11	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12	12	12	12	12	
7 Net Generating Capability (owned)	20	20	20	20	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	
10 Adjusted Net Capability (7+8-9)	14	14	14	14	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	
11 Net Reserve Capacity Obligation (6 x 0.15)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
12 Total Firm Capacity Obligation (5+11)	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	14	14	
13 Surplus or Deficit (-) Capacity (10-12)	1	1	1	1	6	6	6	6	6	6	6	6	6	5	5	5	5	5	5	5	

Falls City Utilities

Seasonal Purchases and Sales and Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Firm	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total Firm Purchases	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Firm Sales																				
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
Planned Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
OPPD	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Sales	0	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total Participation Sales	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
GENERATION																				
Existing	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	20	20	20	20	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25

Fremont Department of Utilities

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	88	90	92	95	97	100	102	105	107	110	113	115	118	121	124	127	131	134	137	141	2.50%
2 Annual System Demand	88	90	92	95	97	100	102	105	107	110	113	115	118	121	124	127	131	134	137	141	
3 Firm Purchases - Total	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	4	4	4	4	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	83	85	88	90	93	95	97	100	103	106	108	111	114	117	120	123	126	130	133	136	
6 Annual Adjusted Net Demand (2-3+4)	83	85	88	90	93	95	97	100	103	106	108	111	114	117	120	123	126	130	133	136	
7 Net Generating Capability (owned)	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	180	180	180	180	180	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	
10 Adjusted Net Capability (7+8-9)	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	161	161	161	161	161	
11 Net Reserve Capacity Obligation (6 x 0.15)	12	13	13	14	14	14	15	15	15	16	16	17	17	18	18	18	19	19	20	20	
12 Total Firm Capacity Obligation (5+11)	96	98	101	104	106	109	112	115	118	121	125	128	131	135	138	142	145	149	153	157	
13 Surplus or Deficit (-) Capacity (10-12)	46	43	40	38	35	32	29	26	23	20	17	13	10	7	3	20	16	12	8	4	

Fremont Department of Utilities

Seasonal Purchases and Sales and Generation in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Firm	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	4	4	4	4
Total Firm Purchases	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	4	4	4	4
Firm Sales																				
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
OPPD	19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Sales	0	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Total Participation Sales	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
GENERATION																				
Existing	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
Fremont CT	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	20	20	20	20
Total	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	180	180	180	180	180

Grand Island Utilities

Committed,Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	159	163	167	171	175	179	184	188	193	198	202	207	212	218	223	228	234	240	246	252	2.45%
2 Annual System Demand	159	163	167	171	175	179	184	188	193	198	202	207	212	218	223	228	234	240	246	252	
3 Firm Purchases - Total	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	150	154	158	162	166	170	175	179	184	189	193	198	203	209	214	219	225	231	237	243	
6 Annual Adjusted Net Demand (2-3+4)	150	154	158	162	166	170	175	179	184	189	193	198	203	209	214	219	225	231	237	243	
7 Net Generating Cap-ability (owned)	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	
8 Participation Purchase -Total	0	0	0	0	15	15	45	45	45	45	45	45	45	45	45	45	45	45	45	45	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	273	273	273	273	288	288	318	318	318	318	318	318	318	318	318	318	318	318	318	318	
11 Net Reserve Capacity Obligation (6 x 0.15)	22	23	24	24	25	25	26	27	28	28	29	30	30	31	32	33	34	35	36	36	
12 Total Firm Capacity Obligation (5+11)	172	177	182	186	191	195	201	206	211	217	222	228	233	240	246	252	259	265	272	279	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	101	96	91	87	97	93	117	112	107	101	96	90	85	78	72	66	59	53	46	39	
14 Surplus or Deficit (-) Capacity @ Planned Obligation	93	88	83	79	88	84	108	102	98	92	86	79	74	67	61	54	47	41	34	27	

Grand Island Utilities

Seasonal Purchases and Sales and Generation in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Firm	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Total Firm Purchases	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Firm Sales																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
OPPD Baseload Purchase	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Hastings WEC#2	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Total Participation Purchases	0	0	0	0	15	15	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Participation Sales																				
Peaking Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION																				
Existing	205	205	205	205	205	205	205	205	205	205	205	205	205	205	205	205	205	205	205	205
Burdick GT2 & 3	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273

Hastings Utilities

Committed,Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	101	103	106	109	112	115	118	121	124	127	130	134	137	141	144	148	152	156	160	164	2.58%
2 Annual System Demand	101	103	106	109	112	115	118	121	124	127	130	134	137	141	144	148	152	156	160	164	
3 Firm Purchases - Total	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	90	92	95	98	101	104	107	110	113	116	119	123	126	130	133	137	141	145	149	153	
6 Annual Adjusted Net Demand (2-3+4)	90	92	95	98	101	104	107	110	113	116	119	123	126	130	133	137	141	145	149	153	
7 Net Generating Capability (owned)	132	132	132	132	352	352	352	352	352	352	352	352	355	359	363	367	372	377	381	386	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	20	15	5	5	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	
10 Adjusted Net Capability (7+8-9)	112	117	127	127	152	152	152	152	152	152	152	152	155	159	163	167	172	177	181	186	
11 Net Reserve Capacity Obligation (6 x 0.15)	13	14	14	15	15	16	16	16	17	17	18	18	19	19	20	20	21	22	22	23	
12 Total Firm Capacity Obligation (5+11)	103	105	109	112	116	119	123	126	129	133	136	141	144	149	152	157	162	166	171	175	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	9	11	18	14	36	33	29	26	22	19	15	11	10	10	10	10	10	10	10	10	
14 Surplus or Deficit (-) Capacity @ Planned Obligation	9	11	8	4	26	23	19	16	12	9	5	1	0	0	0	0	0	0	0	0	

Hastings Utilities

Seasonal Purchases and Sales and Generation in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Firm	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Total Firm Purchases	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Firm Sales																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
MEAN	15	15	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NPPD	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEAN WEC#2	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Grand Island WEC#2	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Uncommitted WEC #2	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Out of State-HCPD-WEC#2	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Total Participation Sales	20	15	5	5	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
GENERATION																				
Existing	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
WEC #2 (Planned)	0	0	0	0	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	3	7	11	15	20	25	29	34
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	132	132	132	132	352	352	352	352	352	352	352	352	355	359	363	367	372	377	381	386

Lincoln Electric System

Committed,Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	749	758	778	795	813	830	845	861	877	892	907	921	944	965	984	1,005	1,027	1,051	1,071	1,091	2.00%
2 Annual System Demand	749	758	778	795	813	830	845	861	877	892	907	921	944	965	984	1,005	1,027	1,051	1,071	1,091	
3 Firm Purchases - Total	127	127	127	126	126	126	126	126	124	124	124	124	124	124	124	124	124	124	124	124	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	622	631	651	670	688	705	720	736	753	768	783	797	820	841	860	881	903	927	947	967	
6 Annual Adjusted Net Demand (2-3+4)	622	631	651	670	688	705	720	736	753	768	783	797	820	841	860	881	903	927	947	967	
7 Net Generating Cap-ability (owned)	566	651	651	651	701	701	751	751	751	751	768	784	810	835	856	881	906	933	956	979	
8 Participation Purchase -Total	272	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	
9 Participation Sales -Total	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
10 Adjusted Net Capability (7+8-9)	828	818	818	818	868	868	918	918	918	918	935	951	977	1,002	1,023	1,048	1,073	1,100	1,123	1,146	
11 Net Reserve Capacity Obligation (6 x 0.15)	93	95	98	100	103	106	108	110	113	115	117	120	123	126	129	132	135	139	142	145	
12 Total Firm Capacity Obligation (5+11)	716	726	749	770	791	810	827	846	866	883	900	916	943	967	989	1,013	1,038	1,066	1,089	1,112	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	113	92	69	48	78	58	91	72	53	35	35	35	35	35	35	35	35	35	35	35	
14 Surplus or Deficit (-) Capacity @ Planned Obligation	78	57	34	13	43	23	56	37	18	0	0	0	0	0	0	0	0	0	0	0	

Lincoln Electric System

Seasonal Purchases and Sales and Generation in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Firm	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
WAPA Peaking	72	72	72	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
WAPA Class II	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Total Firm Purchases	127	127	127	126	126	126	126	126	124	124	124	124	124	124	124	124	124	124	124	124
Firm Sales																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
NPPD - CNS	95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD - GGS	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NPPD - SHELDON	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Total Participation Purchases	272	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
Participation Sales																				
Los Alamos	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Total Participation Sales	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
GENERATION																				
Laramie	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189
J St	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Rokeby 1	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Rokeby 2	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Rokeby 3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Rental Diesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SVS CT1 / CC1	54	118.6	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119
SVS CT 3	27	45.8	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Iatan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CB4	0	0	0	0	50	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Future Baseload	0	0	0	0	0	0	0	0	0	0	17	33	59	84	100	100	100	100	100	100
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23	46
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	30	55	82	82	82
Rokeby Black Start	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
SVS Black Start	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total	566	651	651	651	701	701	751	751	751	751	768	784	810	835	856	881	906	933	956	979

Municipal Energy Agency Of Nebraska

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	192	194	205	207	210	213	215	218	221	224	227	230	233	236	239	242	245	248	251	255	1.50%
2 Annual System Demand	192	194	205	207	210	213	215	218	221	224	227	230	233	236	239	242	245	248	251	255	
3 Firm Purchases - Total	51	51	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	141	144	155	158	160	163	166	169	172	174	177	180	183	186	189	193	196	199	202	205	
6 Annual Adjusted Net Demand (2-3+4)	141	144	155	158	160	163	166	169	172	174	177	180	183	186	189	193	196	199	202	205	
7 Net Generating Capability (owned)	101	101	101	101	151	151	151	151	151	166	166	166	166	166	166	181	181	181	181	186	
8 Participation Purchase -Total	77	88	89	90	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	
9 Participation Sales -Total	0	0	0	0	0	19	16	12	9	20	17	14	10	7	3	15	11	7	4	5	
10 Adjusted Net Capability (7+8-9)	178	188	190	191	206	188	191	194	198	201	204	208	211	215	218	222	225	229	233	237	
11 Net Reserve Capacity Obligation (6 x 0.15)	21	22	23	24	24	24	25	25	26	26	27	27	28	28	28	29	29	30	30	31	
12 Total Firm Capacity Obligation (5+11)	162	165	178	181	184	188	191	194	197	201	204	207	211	214	218	221	225	229	233	236	
13 Surplus or Deficit (-) Capacity (10-12)	16	23	12	9	22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Municipal Energy Agency Of Nebraska

Seasonal Purchases and Sales and Generation in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA - UGPR	17.8	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
WAPA - LAP	32.9	33	32	32	32	32	32	31	31	31	31	31	31	31	31	31	31	31	31	31
Total Firm Purchases	51	51	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
MEAN Wside Import	22	22	24	24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hastings	15	15	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Hastings WEC#2	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
NPPD	40	50	60	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	77	88	89	90	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Participation Sales																				
Peaking Sale	0	0	0	0	0	19	16	12	9	20	17	14	10	7	3	15	11	7	4	5
Total Participation Sales	0	0	0	0	0	19	16	12	9	20	17	14	10	7	3	15	11	7	4	5
GENERATION																				
Ansley	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Arnold	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Beaver City	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Benklemen	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Blue Hill	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Broken Bow	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Burwell	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Callaway	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Chappell	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Crete	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Curtis	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Fairbury	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Kimball	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Oxford	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Pender	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Red Cloud	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Sargent	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Sidney	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Stuart	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
West Point	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
LRS	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
CB4	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	30	30	30	30	35
Total	101	101	101	101	151	151	151	151	151	166	166	166	166	166	166	181	181	181	181	186

Nebraska City Utilities

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	36	37	37	38	38	39	39	40	40	41	41	42	43	43	44	44	45	46	46	47	1.40%
2 Annual System Demand	36	37	37	38	38	39	39	40	40	41	41	42	43	43	44	44	45	46	46	47	
3 Firm Purchases - Total	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	28	28	29	29	30	30	31	32	32	33	33	34	34	35	36	36	37	38	38	39	
6 Annual Adjusted Net Demand (2-3+4)	28	28	29	29	30	30	31	32	32	33	33	34	34	35	36	36	37	38	38	39	
7 Net Generating Capability (owned)	37	37	37	37	37	37	52	52	52	52	52	52	52	52	52	52	52	52	52	52	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	5	5	4	3	3	2	5	5	5	5	5	5	5	5	5	5	5	5	5	5	
10 Adjusted Net Capability (7+8-9)	32	32	33	34	34	35	47	47	47	47	47	47	47	47	47	47	47	47	47	47	
11 Net Reserve Capacity Obligation (6 x 0.15)	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6	
12 Total Firm Capacity Obligation (5+11)	32	32	33	34	34	35	36	36	37	38	38	39	40	40	41	42	42	43	44	45	
13 Surplus or Deficit (-) Capacity (10-12)	0	0	0	0	0	0	12	11	10	10	9	8	8	7	6	5	5	4	3	3	

Nebraska City Utilities

Seasonal Purchases and Sales and Generation in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Firm	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Total Firm Purchases	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Firm Sales																				
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
Planned Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
OPPD	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Sales	0	5	4	3	3	2	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Participation Sales	5	5	4	3	3	2	5	5	5	5	5	5	5	5	5	5	5	5	5	5
GENERATION																				
Existing	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Total	37	37	37	37	37	37	52	52	52	52	52	52	52	52	52	52	52	52	52	52

Nebraska Public Power District

<u>Committed, Planned & Studied</u> Load & Generating Capability in Megawatts

<u>Summer Conditions (May 1 to October 31)</u>

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	2,181	2,216	2,251	2,287	2,323	2,360	2,397	2,434	2,471	2,509	2,547	2,585	2,624	2,663	2,702	2,741	2,780	2,820	2,860	2,900	1.51%
2 Annual System Demand	2,181	2,216	2,251	2,287	2,323	2,360	2,397	2,434	2,471	2,509	2,547	2,585	2,624	2,663	2,702	2,741	2,780	2,820	2,860	2,900	
3 Firm Purchases - Total	451	451	451	447	447	447	447	447	442	442	442	442	442	442	442	442	442	442	442	442	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	1,730	1,764	1,799	1,840	1,876	1,913	1,950	1,987	2,029	2,067	2,105	2,143	2,182	2,221	2,260	2,299	2,338	2,378	2,417	2,457	
6 Annual Adjusted Net Demand (2-3+4)	1,730	1,765	1,800	1,840	1,876	1,913	1,950	1,987	2,029	2,067	2,105	2,143	2,182	2,221	2,260	2,299	2,338	2,378	2,418	2,458	
7 Net Generating Cap-ability (owned)	2,911	2,881	3,108	3,113	3,113	3,113	3,113	3,115	3,113	3,113	3,159	2,677	2,725	2,773	2,821	2,869	2,918	2,967	3,015	3,065	
8 Participation Purchase -Total	5	0	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	
9 Participation Sales -Total	782	707	656	656	656	656	656	656	556	556	556	177	177	177	177	177	177	177	177	177	
10 Adjusted Net Capability (7+8-9)	2,134	2,174	2,452	2,457	2,457	2,457	2,607	2,609	2,707	2,707	2,753	2,650	2,698	2,746	2,794	2,842	2,891	2,940	2,988	3,038	
11 Net Reserve Capacity Obligation (6 x 0.15)+Additional	273	279	285	292	298	304	310	316	323	330	336	342	349	356	362	369	375	382	389	396	
12 Total Firm Capacity Obligation (5+11)	2,003	2,044	2,085	2,132	2,174	2,217	2,260	2,304	2,353	2,397	2,441	2,486	2,531	2,576	2,622	2,667	2,713	2,760	2,806	2,853	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	131	131	368	325	283	240	347	305	354	310	312	164	167	170	172	174	177	180	181	185	
14 Surplus or Deficit (-) Capacity @ Planned Obligation	-1	0	232	187	143	97	203	158	205	159	158	8	9	9	9	9	9	10	9	10	

Nebraska Public Power District

Seasonal Purchases and Sales and Generation in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
Tribal	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
BEAT	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
WALM	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
WAPA Pattern	153	153	153	151	151	151	151	151	149	149	149	149	149	149	149	149	149	149	149	149
WAPA Peaking	288	288	288	285	285	285	285	285	282	282	282	282	282	282	282	282	282	282	282	282
Total Firm Purchases	451	451	451	447	447	447	447	447	442	442	442	442	442	442	442	442	442	442	442	442
Firm Sales																				
NWPS Schedule J	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
In State - Hastings/Neligh	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPPD Baseload Purchase	0	0	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Out of State	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	5	0	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Participation Sales																				
MEAN	40	50	60	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD - CNS	95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD - GGS	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NPPD - SHELDON	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Out of State	470	480	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0
Cooper Nuclear Unspecified	0	0	319	319	379	379	379	379	379	379	379	0	0	0	0	0	0	0	0	0
Total Participation Sales	782	707	656	656	656	656	656	656	556	556	556	177	177	177	177	177	177	177	177	177
GENERATION																				
Existing	2,881	2,881	2,881	2,874	2,874	2,874	2,874	2,874	2,874	2,866	2,866	2,108	2,106	2,106	2,106	2,106	2,103	2,103	2,076	2,023
Beatrice CC	0	0	217	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	330	380	428	476	524	566	566	566	566
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	229
Future Peaking	30	0	10	10	10	10	10	12	10	18	64	10	10	10	10	10	20	69	144	18
Total	2,911	2,881	3,108	3,113	3,113	3,113	3,113	3,115	3,113	3,113	3,159	2,677	2,725	2,773	2,821	2,869	2,918	2,967	3,015	3,065

Omaha Public Power District

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	2,039	2,099	2,153	2,220	2,320	2,381	2,439	2,474	2,515	2,558	2,619	2,675	2,732	2,754	2,805	2,853	2,910	2,971	3,008	3,048	2.14%
2 Annual System Demand	2,039	2,099	2,153	2,220	2,320	2,381	2,439	2,474	2,515	2,558	2,619	2,675	2,732	2,754	2,805	2,853	2,910	2,971	3,008	3,048	
3 Firm Purchases - Total	82	82	82	81	81	81	81	81	80	80	80	80	80	80	80	80	80	80	80	80	
4 Firm Sales - Total	44	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10	
5 Seasonal Adjusted Net Demand (1-3+4)	2,001	2,026	2,080	2,148	2,248	2,309	2,367	2,402	2,444	2,488	2,549	2,605	2,662	2,684	2,735	2,783	2,840	2,901	2,938	2,978	
6 Annual Adjusted Net Demand (2-3+4)	2,001	2,026	2,080	2,148	2,248	2,309	2,367	2,402	2,444	2,488	2,549	2,605	2,662	2,684	2,735	2,783	2,840	2,901	2,938	2,978	
7 Net Generating Capability (owned)	2,547	2,553	2,556	2,556	2,635	2,705	3,156	3,156	3,161	3,211	3,281	3,346	3,411	3,436	3,495	3,550	3,616	3,686	3,729	3,775	
8 Participation Purchase -Total	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	11	11	5	5	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	
10 Adjusted Net Capability (7+8-9)	2,567	2,542	2,551	2,551	2,635	2,705	2,856	2,856	2,861	2,911	2,981	3,046	3,111	3,136	3,195	3,250	3,316	3,386	3,429	3,475	
11 Net Reserve Capacity Obligation (6 x 0.15)	300	304	312	322	337	346	355	360	367	373	382	391	399	403	410	417	426	435	441	447	
12 Total Firm Capacity Obligation (5+11)	2,301	2,330	2,392	2,470	2,585	2,656	2,722	2,763	2,811	2,861	2,931	2,996	3,061	3,087	3,145	3,200	3,266	3,336	3,379	3,425	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	265	212	159	81	50	50	134	94	50	50	50	50	50	50	50	50	50	50	50	50	
14 Surplus or Deficit (-) Capacity @ Planned Obligation	215	162	109	31	0	0	84	44	0	0	0	0	0	0	0	0	0	0	0	0	

Omaha Public Power District

Seasonal Purchases and Sales and Generation in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Pattern	82	82	82	81	81	81	81	81	80	80	80	80	80	80	80	80	80	80	80	80
Total Firm Purchases	82	82	82	81	81	81	81	81	80	80	80	80	80	80	80	80	80	80	80	80
Firm Sales																				
NSP	35																			
Whls Towns	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10
Total Firm Sales	44	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10
Participation Purchases																				
Fremont	19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Falls City	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nebraska City	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
Ames Municipal Utility	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wisconsin Public Service	5	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD Baseload Sale	0	0	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150
GI Baseload Sale	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Unspecified Baseload Sale	0	0	0	0	0	0	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Total Participation Sales	11	11	5	5	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300
GENERATION																				
Fort Calhoun	476	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482
Nebraska City #1	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646
Nebraska City #2	0	0	0	0	0	0	600	600	600	600	600	600	600	600	600	600	600	600	600	600
North Omaha	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663
Sarpy County	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Jones Street	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118
Cass County	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320
Douglas County Landfill	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Douglas County Landfill (Planned)	0	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Tecumseh (leased)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	120	179	234	300	300	300	300
Future Intermediate	0	0	0	0	0	0	0	0	0	0	125	160	160	160	160	160	160	160	160	160
Future Peaking	0	0	0	0	79	149	0	0	5	55	0	30	95	0	0	0	0	70	113	159
Total	2,547	2,553	2,556	2,556	2,635	2,705	3,156	3,156	3,161	3,211	3,281	3,346	3,411	3,436	3,495	3,550	3,616	3,686	3,729	3,775

Other Municipals (Plainview & Wisner)

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	0%
2 Annual System Demand	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	
3 Firm Purchases - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	
6 Annual Adjusted Net Demand (2-3+4)	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	
7 Net Generating Cap-ability (owned)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	
11 Net Reserve Capacity Obligation (6 x 0.15)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
12 Total Firm Capacity Obligation (5+11)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	
13 Surplus or Deficit (-)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Tri-State G&T*

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
1 Seasonal System Demand	305	308	310	317	320	321	329	330	335	337	336	338	343	343	345	347	349	350	352	353	0.77%
2 Annual System Demand	305	308	310	317	320	321	329	330	335	337	336	338	343	343	345	347	349	350	352	353	
3 Firm Purchases - Total	305	308	310	317	320	321	329	330	335	337	336	338	343	343	345	347	349	350	352	353	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
6 Annual Adjusted Net Demand (2-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
7 Net Generating Capability (owned)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
11 Net Reserve Capacity Obligation (6 x 0.15)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
12 Total Firm Capacity Obligation (5+11)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
13 Surplus or Deficit (-) Capacity (10-12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

* Only Tri-State's load in Nebraska is shown and is covered by firm purchases of an equal amount.

Tri-State G&T*

Seasonal Purchases and Sales in Megawatts
Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
LAP Nebr	86	86	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
BASIN	219	221	227	234	237	238	246	247	252	254	253	255	260	260	262	264	266	267	270	270
Total Firm Purchases	305	308	310	317	320	321	329	330	335	337	336	338	343	343	345	347	349	350	352	353
Firm Sales																				
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Wahoo Utilities

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1 Seasonal System Demand	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2 Annual System Demand	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
3 Firm Purchases - Total	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Net Demand (1-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Annual Adjusted Net Demand (2-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Net Generating Capability (owned)																				
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Adjusted Net Capability (7+8-9)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Net Reserve Capacity Obligation (6 x 0.15)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Total Firm Capacity Obligation (5+11)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Surplus or Deficit (-) Capacity (10-12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Wahoo Utilities

Seasonal Purchases and Sales in Megawatts

Summer Conditions (May 1 to October 31)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Purchases																				
WAPA Firm	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Firm Purchases	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Firm Sales																				
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
NPPD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

APPENDIX C

Statewide Existing Electric Generating Plants

Utility	Unit Name	Baseload Peaking	Unit Type	Fuel Type	Commercial Date	Accredited Capacity	Utility Capacity
Falls City	Falls City #1	P	D	O	1930	0.70	
	Falls City #2	P	D	O	1937	1.00	
	Falls City #3	P	D	NG/O	1965	2.30	
	Falls City #4	P	D	NG/O	1946	0.80	
	Falls City #5	P	D	NG/O	1951	1.40	
	Falls City #6	P	D	NG/O	1958	2.00	
	Falls City #7	P	D	NG/O	1972	6.20	
	Falls City #8	P	D	NG/O	1981	6.00	
Falls City	**Total**						**20.40**
Fremont	**Fremont #6**	**B**	**F**	**C/NG**	**1958**	**17.50**	
	Fremont #7	**B**	**F**	**C/NG**	**1963**	**22.40**	
	Fremont #8	**B**	**F**	**C/NG**	**1977**	**84.40**	
	CT		CT	NG/O	2003	36.00	
Fremont	**Total**						**160.30**
Grand Island	Burdick #1	P	F	NG/O	1957	16.00	
	Burdick #2	P	F	NG/O	1963	22.00	
	Burdick #3	P	F	NG/O	1972	54.00	
	Burdick GT1	P	CT	NG/O	1968	13.00	
	Burdick GT2	P	CT	NG/O	2003	34.00	
	Burdick GT3	P	CT	NG/O	2003	34.00	
	Platte Generating Station	**B**	**F**	**C**	**1982**	**100.00**	
Grand Island	**Total**						**273.00**
Hastings	**Whelan Energy Center #1**	**B**	**F**	**C**	**1981**	**77.00**	
	Hastings-NDS#4	P	F	NG/O	1957	13.00	
	Hastings-NDS#5	P	F	NG/O	1967	24.00	
	DHPC-#1	P	CT	NG/O	1972	18.00	
Hastings	**Total**						**132.00**
LES	**Laramie**	**B**	**F**	**C**	**1982**	**189.10**	
	J St	P	CT	NG/O	1972	30.30	
	Rokeby 1	P	CT	NG/O	1982	74.50	
	Rokeby 2	P	CT	NG/O	1997	88.30	
	Rokeby 3	P	CT	NG/O	2001	99.90	
	Wind units	P	R	W	1999	0.00	
	Rokeby Black Start	P	D	O	1997	3.10	
	Salt Valley	P	CC	NG/O	2003	54.00	
	Salt Valley	P	CT	NG/O	2003	27.00	
LES	**Total**						**566.20**
MEAN	Ansley #1	P	D	NG/O	1972	**0.40**	
	Ansley #2	P	D	NG/O	1968	**0.80**	
	Arnold #1	P	D	NG/O	1960	**0.40**	
	Arnold #2	P	D	NG/O	1942	**0.20**	
	Arnold #3	P	D	NG/O	1946	**0.30**	
	Beaver City #1	P	D	NG/O	1958	**0.40**	
	Beaver City #2	P	D	NG/O	1961	**0.30**	
	Beaver City #4	P	D	NG/O	1968	**0.45**	
	Benkelman #1	P	D	NG/O	1968	**0.75**	
	Blue Hill#1	P	D	NG/O	1964	**0.80**	
	Blue Hill#2	P	D	O	1948	**0.40**	
	Broken Bow #1	P	D	O	1933	**0.50**	
	Broken Bow #2	P	D	NG/O	1971	**3.20**	
	Broken Bow #3	P	D	NG/O	1936	**0.80**	
	Broken Bow #4	P	D	NG/O	1949	**0.80**	
	Broken Bow #5	P	D	NG/O	1959	**1.00**	
	Broken Bow #6	P	D	NG/O	1961	**2.00**	
	Burwell#1	P	D	NG/O	1955	**0.50**	
	Burwell#2	P	D	NG/O	1962	**0.70**	
	Burwell#3	P	D	NG/O	1967	**0.90**	
	Burwell#4	P	D	NG/O	1972	**0.90**	

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**
R-renewable	**UR-Uranium**
	L=Landfill Gas
	W-Wind

APPENDIX C (continued)

MEAN(cont)	Callaway #1	P	D	O	1936	**0.18**	
	Callaway #2	P	D	O	1948	**0.18**	
	Callaway #3	P	D	O	1958	**0.50**	
	Chappell #2	P	D	O	1945	**0.20**	
	Chappell #3	P	D	O	1982	**0.90**	
	Crete #1	P	D	NG/O	1939	**0.50**	
	Crete #2	P	D	NG/O	1955	**1.10**	
	Crete #3	P	D	NG/O	1951	**0.90**	
	Crete #4	P	D	NG/O	1947	**0.90**	
	Crete #5	P	D	NG/O	1962	**2.70**	
	Crete #6	P	D	NG/O	1965	**3.50**	
	Crete #7	P	D	NG/O	1972	**6.07**	
	Curtis #1	P	D	NG/O	1975	**1.20**	
	Curtis #2	P	D	NG/O	1969	**0.90**	
	Curtis #3	P	D	NG/O	1955	**0.90**	
	Fairbury #2	P	F	NG/O	1948	**4.30**	
	Fairbury #4	P	F	NG/O	1966	**11.00**	
	Kimball #1	P	D	NG/O	1955	**1.00**	
	Kimball #2	P	D	NG/O	1956	**0.90**	
	Kimball #3	P	D	NG/O	1959	**1.00**	
	Kimball #4	P	D	NG/O	1960	**0.90**	
	Kimball #5	P	D	NG/O	1951	**0.70**	
	Kimball #7	P	D	NG/O	1975	**3.50**	
	Laramie #1	**B**	**F**	**C**	**1982**	**10.00**	
	Oxford #1	P	D	O	1948	**0.54**	
	Oxford #2	P	D	NG/O	1952	**0.53**	
	Oxford #3	P	D	NG/O	1956	**0.76**	
	Oxford #4	P	D	NG/O	1956	**0.47**	
	Oxford #5	P	D	O	1972	**1.00**	
	Pender #1	P	D	O	1967	**1.06**	
	Pender #2	P	D	NG/O	1973	**1.71**	
	Pender #3	P	D	O	1953	**0.44**	
	Pender #4	P	D	O	1961	**0.74**	
	Pender #5	P	D	O	1939	**0.00**	
	Red Cloud #2	P	D	NG/O	1953	**0.50**	
	Red Cloud #3	P	D	NG/O	1960	**1.00**	
	Red Cloud #4	P	D	NG/O	1968	**1.00**	
	Red Cloud #5	P	D	NG/O	1974	**1.50**	
	Sargent #1	P	D	NG/O	1963	**1.20**	
	Sargent #2	P	D	NG/O	1964	**0.50**	
	Sargent #3	P	D	NG/O	1966	**0.30**	
	Sidney #1	P	D	NG/O	1967	**1.00**	
	Sidney #2	P	D	NG/O	1973	**2.50**	
	Sidney #3	P	D	O	1953	**0.65**	
	Sidney #4	P	D	NG/O	1961	**0.85**	
	Sidney #5	P	D	NG/O	1939	**3.00**	
	Stuart #1	P	D	NG/O	1965	**0.70**	
	Stuart #2	P	D	NG/O	1996	**0.80**	
	Stuart #3	P	D	O	1954	**0.30**	
	Stuart #4	P	D	O	1946	**0.30**	
	West Point #1	P	D	NG/O	1950	**2.05**	
	West Point #2	P	D	NG/O	1959	**0.95**	
	West Point #3	P	D	NG/O	1965	**0.59**	
	West Point #5	P	D	NG/O	1971	**3.85**	
MEAN	**Total**						**101.22**
Nebraska City	Nebraska City #2 Black start	P	D	NG/O	1953	1.00	
	Nebraska City #3	P	D	NG/O	1955	2.00	
	Nebraska City #4	P	D	NG/O	1957	2.50	
	Nebraska City #5 Black start	P	D	NG/O	1964	1.60	
	Nebraska City #6	P	D	NG/O	1967	1.50	
	Nebraska City #7	P	D	NG/O	1969	1.50	
	Nebraska City #8	P	D	NG/O	1970	3.50	
	Nebraska City #9	P	D	NG/O	1974	5.60	
	Nebraska City #10	P	D	NG/O	1979	5.80	
	Nebraska City #11	P	D	NG/O	1998	3.80	
	Nebraska City #12	P	D	NG/O	1998	3.80	
	Nebraska City #13	P	D	O	1998	4.50	
Nebraska City	**Total**						**37.10**

APPENDIX C (continued)

NPPD	Auburn #1	P	D	NG/O	1982	2.10
	Auburn #2	P	D	NG/O	1949	0.50
	Auburn #4	P	D	NG/O	1993	3.30
	Auburn #5	P	D	NG/O	1973	3.00
	Auburn #6	P	D	NG/O	1967	2.20
	Auburn #7	P	D	NG/O	1987	5.20
	Belleville 4	P	D	NG/O	1955	0.80
	Belleville 6	P	D	NG/O	1966	3.10
	Belleville 7	P	D	NG/O	1971	4.10
	Cambridge 1	P	D	NG	1958	0.60
	Cambridge 2	P	D	NG	1963	0.65
	Cambridge 3	P	D	NG	1972	1.25
	Canaday	P	F	NG/O	1958	117.95
	Columbus 1	**B**	**H**	**HR**	**1936**	**11.10**
	Columbus 2	**B**	**H**	**HR**	**1936**	**12.58**
	Columbus 3	**B**	**H**	**HR**	**1936**	**11.85**
	Cooper	**B**	**N**	**UR**	**1974**	**758.00**
	David City 1	P	D	NG/O	1960	1.30
	David City 2	P	D	NG/O	1949	0.80
	David City 3	P	D	NG/O	1955	0.90
	David City 4	P	D	NG/O	1966	1.80
	David City 5	P	D	O	1996	1.33
	David City 6	P	D	O	1996	1.33
	David City 7	P	D	O	1996	1.34
	Deshler 1	P	D	NG/O	2001	0.27
	Deshler 2	P	D	NG/O	1950	0.28
	Deshler 3	P	D	NG/O	1998	1.10
	Deshler 4	P	D	NG/O	1956	0.60
	Emerson #2	P	D	NG/O	1968	1.15
	Emerson #3	P	D	NG/O	1948	0.15
	Emerson #4	P	D	O	1958	0.40
	Franklin 1	P	D	NG	1963	0.65
	Franklin 2	P	D	NG	1974	1.35
	Franklin 3	P	D	NG	1968	1.05
	Franklin 4	P	D	NG	1955	0.70
	Gentleman 1	**B**	**F**	**C**	**1979**	**665.00**
	Gentleman 2	**B**	**F**	**C**	**1982**	**700.00**
	Hallam (Black Start)	P	CT	NG/O	1973	52.00
	Hebron	P	CT	NG/O	1973	52.00
	Holdrege 1	P	D	O	1938	0.00
	Holdrege 2	P	D	O	1952	0.00
	Holdrege 3	P	D	O	1945	0.00
	Jeffrey 1	**B**	**H**	**HR**	**1940**	**9.00**
	Jeffrey 2	**B**	**H**	**HR**	**1940**	**9.00**
	Johnson I 1	**B**	**H**	**HR**	**1940**	**9.00**
	Johnson I 2	**B**	**H**	**HR**	**1940**	**9.00**
	Johnson II	**B**	**H**	**HR**	**1940**	**18.00**
	Kearney	**B**	**H**	**HR**	**1921**	**1.00**
	Kingsley(Black Start)	**B**	**H**	**HR**	**1985**	**38.00**
	Lodgepole 1	P	D	O	1934	0.00
	Lodgepole 2	P	D	O	1947	0.00
	Lyons 2	P	D	O	1960	0.20
	Lyons 3	P	D	O	1953	0.90
	Madison 1	P	D	NG/O	1969	1.70
	Madison 2	P	D	NG/O	1959	0.95
	Madison 3	P	D	NG/O	1953	0.85
	Madison 4	P	D	O	1946	0.50
	McCook(Black Start)	P	CT	O	1973	51.00
	Monroe	**B**	**H**	**HS**	**1936**	**3.00**
	Mullen #1	P	D	O	1958	0.35
	Mullen #2	P	D	O	1966	0.65
	North Platte 1(Black Start)	**B**	**H**	**HR**	**1935**	**12.00**
	North Platte 2(Black Start)	**B**	**H**	**HR**	**1935**	**12.00**
	Ord 1	P	D	NG/O	1973	5.00
	Ord 2	P	D	NG/O	1966	1.00
	Ord 3	P	D	NG/O	1963	2.00
	Ord 4	P	D	O	1997	1.40
	Ord 5	P	D	O	1997	1.40
	Sheldon 1	**B**	**F**	**C**	**1961**	**105.00**
	Sheldon 2	**B**	**F**	**C**	**1965**	**120.00**
	Spalding 2	P	D	O	1955	0.40
	Spalding 3	P	D	O	1975	1.40
	Spalding 4	P	D	O	1999	0.20
	Spalding 5	P	D	O	2001	0.25

APPENDIX C (continued)

NPPD (cont)	**Spencer 1**	**B**	**H**	**HS**	**1927**	**0.80**	
	Spencer 2	**B**	**H**	**HS**	**1952**	**1.00**	
	Springview	P	R	W	1998	0.00	
	Sutherland 1	P	D	O	1952	0.45	
	Sutherland 2	P	D	O	1959	0.85	
	Sutherland 3	P	D	O	1935	0.00	
	Sutherland 4	P	D	O	1964	1.35	
	Wahoo #1	P	D	NG/O	1960	1.70	
	Wahoo #3	P	D	NG/O	1973	3.60	
	Wahoo #5	P	D	NG/O	1952	1.80	
	Wahoo #6	P	D	NG/O	1969	2.90	
	Wakefield 2	P	D	NG/O	1955	0.54	
	Wakefield 4	P	D	NG/O	1961	0.69	
	Wakefield 5	P	D	NG/O	1966	1.08	
	Wakefield 6	P	D	NG/O	1971	1.13	
	Wayne 1	P	D	O	1951	0.75	
	Wayne 3	P	D	O	1956	1.75	
	Wayne 4	P	D	O	1960	1.85	
	Wayne 5	P	D	O	1966	3.25	
	Wayne 6	P	D	O	1968	4.90	
	Wayne 7	P	D	O	1998	3.25	
	Wayne 8	P	D	O	1998	3.25	
	Wilber 4	P	D	O	1949	0.78	
	Wilber 5	P	D	O	1958	0.59	
	Wilber 6	P	D	O	1996	1.57	
	York 1	P	D	O	1980	1.00	
	York 2	P	D	O	1996	1.60	
NPPD	**Total**						**2881.34**
OPPD	**Fort Calhoun #1**	**B**	**N**	**UR**	**1973**	**476.00**	
	Nebraska City #1	**B**	**F**	**C**	**1979**	**646.00**	
	North Omaha #1	**B**	**F**	**C/NG**	**1954**	**78.60**	
	North Omaha #2	**B**	**F**	**C/NG**	**1957**	**111.00**	
	North Omaha #3	**B**	**F**	**C/NG**	**1959**	**111.00**	
	North Omaha #4	**B**	**F**	**C/NG**	**1963**	**138.20**	
	North Omaha #5	**B**	**F**	**C/NG**	**1968**	**224.00**	
	Jones St. #1	P	CT	O	1973	59.20	
	Jones St. #2	P	CT	O	1973	59.20	
	Cass County #1	P	CT	NG	2003	160.00	
	Cass County #2	P	CT	NG	2003	160.00	
	Sarpy County #1	P	CT	NG/O	1972	55.20	
	Sarpy County #2	P	CT	NG/O	1972	55.20	
	Sarpy County #3	P	CT	NG/O	1996	105.50	
	Sarpy County #4	P	CT	NG/O	2000	47.50	
	Sarpy County #5	P	CT	NG/O	2000	47.50	
	Sarpy Co. Black Start	P	D	O	1996	3.40	
	Elk City Station	**B**	**D,R**	**L**	**2002**	**3.00**	
	Tecumseh #1	P	D	O	1949	0.60	
	Tecumseh #2	P	D	O	1968	1.40	
	Tecumseh #3	P	D	O	1952	1.00	
	Tecumseh #4	P	D	O	1960	1.20	
	Tecumseh #5	P	D	O	1993	2.40	
OPPD	**Total**						**2547.10**
Other Municipals	Plainview #1	P	D	NG/O	1948	1.10	
	Plainview #3	P	D	NG/O	1957	0.90	
	Plainview #4	P	D	NG/O	1962	1.25	
	Plainview #5	P	D	NG/O	1962	1.83	
	Wisner #1	P	D	NG/O	1954	0.48	
	Wisner #2	P	D	O	1947	0.31	
	Wisner #3	P	D	O	1969	0.66	
Other Municipals	**Total**						**6.53**

Nebraska Grand Total	**TOTAL**	**6725.19**
	MEC share of Cooper	**-379.00**
	Remaining	**6346.19**

APPENDIX D

Demand-Side Management

APPENDIX D

2005 DSM Summary

forecast effects					DSM not in Forecast			
Option	Option Peak	Effective Demand	Energy		Option	Option Peak	Effective Demand	Energy
Auburn					AC LC		0.65	
Falls City								
Audits	0.10	0.10	75					
Building Codes	0.20	0.20	100					
Lighting	0.10	0.00	50					
Fremont								
Interruptible	1.50	1.50	75					
Direct load Control	4.50	1.50	120					
Motors	1.00	1.00	430					
Grand Island								
Rates-summer increase block, winter decline								
Hastings								
Interruptible Irrigation	2.00	2.00						
LES					Heating and Cooling	4.00	4.00	(122,173)
Curtailable Load	14.00	11.00	125		Lighting	12.00	12.00	41,400
					Com Geothermal	1.00	1.00	891
					Distributed Wind	1.30		2,700
MEAN								
Direct load control-Wells	15.00	13.00	-		Appliance rebate	2.00	2.00	5,228
Nebraska City								
NPPD								
Irrigation	687.00	371.00	-					
Direct load control	110.00	45.00	-					
Distributed Generation	1.00	0.00	200					
Voltage control	10.00	5.00	300					
Energy Curtailment Prog	155.00	25.00						
Distributed Gen-Wholesale	40.00	5.00	9,000					
Time of use rates	60.00	20.00	180,000					
OPPD								
Curtailable Load	108.50	108.50	2,600		Voluntary Load Reduction	16.88	16.88	100
Tri-State								
Heating & Cooling	(6.70)	(5.10)	(14,400)					
Water Heating	(2.40)	(1.80)	(1,800)					
Motors	(45.20)	(33.90)	(46,330)					
Wahoo								
Total included in forecast	1155.60	569.00	130,545		Total not in forecast	37.18	36.53	(71,854)
		MW	%					
Irrigation		386.00	67.84%					
Curtailable		121.00	21.27%					
Direct Load control		46.50	8.17%		10.90%			
Other		15.50	2.72%					
		569.00	100.00%					

APPENDIX E

Future Generators

Appendix E
Committed,Planned and Studied Capability Data

Utility	Unit Name	New Existing*	Committed	Planned	Studied	Unit Type	Fuel Type	Accredited Capacity	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Falls City	Future Base				S			0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Falls City	**Total**							0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fremont	CT Peaking Unit #1	E				CT	NG/O	124.3	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
	Future Base				S			0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fremont	**Total**							124.3	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
Grand Island	Burdick GT2, GT3	E				CT	NG/O	68.0	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Grand Island	**Total**							68.0	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Hastings	WEC #2			P		F	C	220.0	0	0	0	0	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
	Future Peak				S			34.0	0	0	0	0	0	0	0	0	0	0	0	0	3	7	11	15	20	25	29	34
Hastings	**Total**							254.0	0	0	0	0	220	220	220	220	220	220	220	220	223	227	231	235	240	245	249	254
LES	SVGS-CC	E				CC	NG/O	54.0	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
	SVGS-CC		C			CC	NG/O	64.6	0	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	SVGS-CT#1	E				CT	NG/O	27.0	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
	SVGS-CT#2		C			CT	NG/O	18.8	0	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
	SVGS-Black		C			D	NG/O	1.5	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Council Bluffs #4		C			F	C	100.0	0	0	0	0	50	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	Future Base				S			100.0	0	0	0	0	0	0	0	0	0	0	17	33	59	84	100	100	100	100	100	100
	Future Intermediate				S			46.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23	46
	Future Peak				S			82.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	30	55	82	82	82
LES	**Total**							493.9	81	166	166	166	216	216	266	266	266	266	283	299	325	350	371	396	421	448	471	494
MEAN	Council Bluffs #4		C			F	C	50.0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	Future Base				S			30.0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	30	30	30	30
MEAN	**Total**							50.0	0	0	0	0	50	50	50	50	50	50	65	65	65	65	65	65	80	80	80	80
Nebraska City	Future Base				S			0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nebraska City	**Total**							0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD	Beatrice		C			CC	NG/O	229.0	0	0	217	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229
	Future Base				S			566.0	0	0	0	0	0	0	0	0	0	0	0	330	380	428	476	524	566	566	566	566
	Future Intermediate				S			229.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	229
	Future Peak				S			144.0	30	0	10	10	10	10	10	12	10	18	64	10	10	10	10	10	20	69	144	18
NPPD	**Total**							1168.0	30	0	227	239	239	239	239	241	239	247	293	569	619	667	715	763	815	864	939	1042
OPPD	Nebraska City #2		C			F	C	600.0	0	0	0	0	0	0	600	600	600	600	600	600	600	600	600	600	600	600	600	600
	Cass County #1, #2	E				CT	NG/O	320.0	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320
	Future Base				S	R	L	3.0	0	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Future Base				S			300.0	0	0	0	0	0	0	0	0	0	0	0	0	0	120	179	234	300	300	300	300
	Future Intermediate				S			160.0	0	0	0	0	0	0	0	0	0	0	125	160	160	160	160	160	160	160	160	160
	Future Peak				S			159.0	0	0	0	0	79	149	0	0	5	55	0	30	95	0	0	0	0	70	113	159
OPPD	**Total**							1542.0	320	320	323	323	402	472	923	923	928	978	1048	1113	1178	1203	1262	1317	1383	1453	1496	1542
	Nebraska Grand Total							**3700.2**	623	678	908	920	1319	1389	1890	1892	1895	1953	2101	2458	2602	2704	2836	2968	3131	3282	3427	3604

Unit Type	Fuel type
H-Hydro	**HS-Run of River**
D-Diesel	**NG-Natural Gas**
N-Nuclear	**O-Oil**
CT-Combustion Turbine	**C-Coal**
CC-Combined Cycle	**HR- Reservoir**
F-Fossil (Pulverized Coal)	**UR-Uranium**
R-renewable	**W-Wind**
	L-Landfill Gas

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
New Existing	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3	593.3
Committed	0	85	302	314	414	414	1064	1064	1064	1064	1064	1064	1064	1064	1064	1064	1064	1064	1064	1064
Planned	0	0	0	0	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Future Peak	30	0	10	10	89	159	10	12	15	73	64	40	108	17	26	55	95	246	368	293
Future Intermediate	0	0	0	0	0	0	0	0	0	0	125	160	160	160	160	160	160	160	183	435
Future Base	0	0	3	3	3	3	3	3	3	3	35	381	457	650	773	876	999	999	999	999
	623.3	678	908	920	1319	1389	1890	1892	1895	1953	2101	2458	2602	2704	2836	2968	3131	3282	3427	3604
Committed - NG/O	0	85	302	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Committed - Coal	0	0	0	0	100	100	750	750	750	750	750	750	750	750	750	750	750	750	750	750
	0	85	302	314	414	414	1064	1064	1064	1064	1063.9	1064	1064	1064	1064	1064	1064	1064	1064	1064

APPENDIX F

Screening Curves

Supply-Side Screening Curve Data

2003$

Inputs:

Coal / Natural Gas/Oil

Inputs:	Unit	Coal: Neb City 600 MW	Coal: Neb City 300 MW	Coal: Greenfield 600 MW	Coal: Greenfield 300 MW	Coal: Greenfield 150 MW	Coal: Fluid Bed 200 MW	Coal: Intg Gas CC 590 MW	Natural Gas/Oil: Gas Turbine 110 MW	Natural Gas/Oil: LM 6000	Natural Gas/Oil: Combined Cycle 260 MW	Natural Gas/Oil: Ph Acid Fuel Cell	Natural Gas/Oil: Diesel
Size	MW	1x500	2x275	1x500	2x275	150	200	590	110	46	262	100	5
Production Plant	$/kW	1,034	1,100	1,034	1,100	1,335	1,463	1,269	399	729	541	4,255	707
Transmission	$/kW	84	84	84	84	84	84	84	24	24	24	0	24
Decommissioning	$/kW	0	0	0	0	0	0	0	0	0	0	0	0
Replacements	$/kW	0	0	175	186	0	0	0	0	0	0	0	0
Owner Cost	$/kW	51	57	51	57	69	62	75	11	20	15	66	27
Subtotal	$/kW	1,168	1,240	1,343	1,426	1,488	1,609	1,428	434	773	580	4,322	758
Escalation,Interest Factor	$/kW	115	123	134	143	142	172	142	0	0	29	147	0
Total Installed Cost	$/kW	1,283	1,363	1,477	1,569	1,630	1,781	1,570	434	773	609	4,468	758
Capacity Value	**Ratio**	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Energy Value	**Ratio**	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Real Fuel Cost	$/MBtu	0.65	0.65	0.65	0.65	0.65	0.65	0.65	3.97	3.97	3.97	3.97	6.20
Heat Rate	Btu/kWh	9,942	10,141	9,942	10,141	10,242	9,940	8,308	12,127	10,746	7,249	9,760	8,740
Fixed O&M	$/kW-yr	29.16	35.41	32.40	39.34	47.77	44.40	39.70	9.20	17.80	9.40	11.50	24.85
A&G & Insurance	$/kW-yr	2.46	2.77	2.62	2.97	3.39	3.22	2.99	1.46	1.89	1.47	1.58	2.24
TOTAL O&M	$/kW-yr	31.62	38.18	35.02	42.31	51.16	47.62	42.69	10.66	19.69	10.87	13.08	27.09
Variable O&M	$/MWh	1.45	1.76	1.61	1.95	2.37	1.40	1.90	11.60	21.00	2.30	2.30	4.51
Environmental *	$/MWh	0.54	0.55	0.54	0.55	0.56	0.33	0.19	0.28	0.25	0.06	0	7.00
Efficiency Ratio	O/I	0	0	0	0	0	0	0	0	0	0	0	0
Pumping Cost	$/MWh	0	0	0	0	0	0	0	0	0	0	0	0
Tipping Fee	$/Ton	0	0	0	0	0	0	0	0	0	0	0	0
Conversion Tons/MW-Day		0	0	0	0	0	0	0	0	0	0	0	0
Life	Years	30	30	30	30	30	30	30	30	30	30	30	30
Maintenance Outage Rat	%	11.1	11.1	11.1	11.1	10.6	5.7	4.7	6.9	6.9	6.9	1.1	5.0
Forced Outage Rate	%	4.9	4.9	4.9	4.9	4.4	4.1	10.1	10.4	10.4	4.6	1.8	1.0
Equivalent Availability	%	84.5	84.5	84.5	84.5	85.5	90.4	85.7	83.4	83.4	88.8	97.1	94.1
SO2 Emissions	lb/MBtu	0.130	0.130	0.130	0.130	0.130	0.042	0.043	0.016	0.016	0.011	0	0.056
NOx Emissions	lb/MBtu	0.150	0.150	0.150	0.150	0.150	0.085	0.065	0.080	0.082	0.030	0	2.900
CO2 Emissions	lb/MBtu	213	213	213	213	213	193	223	110	108	110	108	162.00
Part Emissions	lb/MBtu	0.020	0.020	0.020	0.020	0.020	0.031	0.011	0	0	0	0	0
Real Fixed Charge Rate		5.322%	5.322%	5.322%	5.322%	5.322%	5.322%	5.322%	5.322%	5.322%	5.322%	5.322%	5.322%
Preconst, License Design	years	1	1	1	1	1	3	3	1	1	2	2	1
Idealized Plant Construction	years	3	3	3	3	3	3	3	1	1	2	2	1
AFUDC/Esclation Adder		10.7%	10.7%	10.7%	10.7%	10.7%	11.8%	11.2%	0%	0%	5.4%	3.5%	0%
Cost Confidence	+	10%	10%	10%	10%	10%	15%	25%	10%	10%	10%	30%	10%
	-	10%	10%	10%	10%	10%	15%	25%	10%	10%	10%	30%	10%
Cost Based On		BLUS	BLUS	Calc	Calc	Calc	EPRI	EPRI	EPRI	EPRI	EPRI	EPRI	EPRI
1996 EPRI Tag Guide Page #													
2000 EPRI Tag Guide Page #										5-66		2-113 l/99	2-40
2001 EPRI Tag Guide Page #		5-22	5-22	5-22	5-22	5-22	5-37	5-29	5-49		5-52		
2002 EPRI Tag Guide Page #		5-30	5-30	5-30	5-30	5-30	5-61	5-38	5-82	5-81	5-85		

Renewables/Other / Storage

Inputs:	Unit	AP 600 Nuclear	Whole Tree	Switch Grass	Municipal Solid Waste	Coal, Wood Retrofit	Solar Thermal	Solar Photo Voltaic	Wind w/CT backup	Wind w/o Backup	Landfill Gas	Storage: Pumped Storage	Storage: CAES	Storage: Adv Battery 8 hr
Size	MW	1x600	100	75	40	10	80	50	100	100	6.0	1050	350	15
Production Plant	$/kW	1,768	1,649	2,137	5,439	2,621	3,090	7,984	847	847	1,530	840	520	819
Transmission	$/kW	84	84	84	24	0	24	24	24	24	110	84	84	24
Decommissioning	$/kW	661	0	0	0	0	0	0	0	0	0	0	0	0
Replacements	$/kW	0	0	0	0	0	0	0	0	0	0	0	0	0
Owner Cost	$/kW	130	83	12	271	0	74	239	0	0	0	31	18	41
Subtotal	$/kW	2,642	1,815	2,232	5,733	2,621	3,188	8,247	870	870	1,640	954	622	884
Escalation,Interest Factor	$/kW	318	93	140	186	0	0	0	0	0	0	189	82	0
Total Installed Cost	$/kW	2,960	1,908	2,373	5,919	2,621	3,188	8,247	870	870	1,640	1,143	704	884
Capacity Value	**Ratio**	1.0	1.0	1.0	1.0	1.0	1.0	0.80	0.17	1.00	1.0	1.0	1.0	1.0
Energy Value	**Ratio**	1.0	1.0	1.0	1.0	1.0	1.0	0.80	0.17	1.00	1.0	1.0	1.0	1.0
Real Fuel Cost	$/MBtu	0.52	2.42	4.67	0	0.79	0	0	0	0	0.470	0	3.97	0
Heat Rate	Btu/kWh	10,510	10,500	8,500	16,870	11,600	0	0	0	0	12,053	0	4,050	0
Fixed O&M	$/kW-yr	87.50	56.22	46.40	173.1	5.24	59.60	13.53	20.58	20.58	104.73	4.40	5.63	1.02
A&G & Insurance	$/kW-yr	5.38	3.81	3.32	9.65	1.26	3.98	1.68	2.03	2.03	6.24	1.22	1.28	1.05
TOTAL O&M	$/kW-yr	92.88	60.03	49.72	182.74	6.51	63.58	15.20	22.61	22.61	110.97	5.62	6.91	2.08
Variable O&M	$/MWh	0.30	1.95	10.39	22.21	1.15	0	0	0	0	0	4.40	2.05	10.24
Environmental *	$/MWh	0	0.10	0	0.66	0.11	0	0	0	0	0	0	0.09	0
Efficiency Ratio	O/I	0	0	0	0	0	0	0	0	0	0	0.77	1.39	0.82
Pumping Cost	$/MWh	0	0	0	0	0	0	0	0	0	0	10.95	6.06	10.27
Tipping Fee	$/Ton	0	0	0	20.95	0	0	0	0	0	0	0	0	0
Conversion Tons/MW-Day		0	0	0	40.2	0	0	0	0	0	0	0	0	0
Life	Years	30	30	30	20	10	30	30	30	30	30	50	30	30
Maintenance Outage Rat	%	7.3	7.7	7.7	5.6	7.7	3.8	3.8	1.5	1.5	1.5	5.0	2.3	1.9
Forced Outage Rate	%	7.7	8.2	8.2	10.0	11.0	4.0	3.0	0.5	0.5	1.5	5.0	0.5	4.0
Equivalent Availability	%	85.6	84.8	84.8	85.0	82.2	92.3	93.3	98.0	98.0	97.0	90.3	97.2	94.2
SO2 Emissions	lb/MBtu	0	0.003	0	0.069	0.003	0	0	0	0	0	0	0	0
NOx Emissions	lb/MBtu	0	0.018	0	0.100	0.018	0	0	0	0	0	0	0.080	0
CO2 Emissions	lb/MBtu	0	0	0	195	0	0	0	0	0	0	0	110	0
Part Emissions	lb/MBtu	0	0.02	0	0.03	0.02	0	0	0	0	0	0	0	0
Real Fixed Charge Rate		5.322%	5.322%	5.322%	6.861%	11.671%	5.322%	5.322%	5.322%	5.322%	5.322%	4.199%	5.322%	5.322%
Preconst, License Design	years	4	2	1	2	2	1	1	2	2	2	2	2	1
Idealized Plant Construction	years	4	2	2	2	1	1	1	1	1	1	6	2	1
AFUDC/Esclation Adder		18.0%	5.7%	6.6%	3.4%	0%	0%	0%	0%	0%	0%	22.6%	15.7%	0.0%
Cost Confidence	+	100%	100%	?	20%	20%	10%	100%	25%	0	25%	0%	30%	100%
	-	30%	30%	?	20%	20%	10%	30%	25%	0	25%	0%	25%	30%
Cost Based On		EPRI	EPRI	NPA	EPRI	EPRI	EPRI	EPRI	EPRI	EPRI	OPPD	EPRI	EPRI	EPRI
1996 EPRI Tag Guide Page #					8 - 153						8 - 145			
2000 EPRI Tag Guide Page #														
2001 EPRI Tag Guide Page #		5-55												
2002 EPRI Tag Guide Page #		5-91	4-40			4-40	7-16	5-16	3-27	3-27		2-37	2 - 12	2 - 22

SOURCES: EPRI: Technical Assessment Guide (TAG).
NPA: Statewide IRP Coordination Report, dated October 1996.
BLUS: Estimates from 1999 Baseload Unit Study.

SO2 Emission Cost	131	$/ton
NOx Emission Cost	550	$/ton
CO2 Emission Cost	0	$/ton
Particulate Emission Cost	450	$/ton

Inflation Rate	2.40%
Interest Rate	6.10%
Real Disc Rate	3.61%

Administrative & General Expense	5.00%	(of Fixed O&M)
Insurance ($/kW-yr)	1.000	
Escalation Rate	2.40%	

* Encompasses the residual gases SO2, NOx, and particulates.

Supply Side Screening Curve Analysis

2003

Real - $/kW-year

Capacity Factor	Neb City 600 MW	Neb City 300 MW	Greenfield 600 MW	Greenfield 300 MW	Greenfield 150 MW	Fluid Bed 200 MW	Intg Gas CC 590 MW	Gas Turbine 110 MW	LM 6000	Combined Cycle 260 MW	Ph Acid Fuel Cell	Diesel
0%	100	111	114	126	138	142	126	34	61	43	251	67
1%	101	112	114	127	139	143	127	39	66	46	254	73
3%	102	113	116	128	140	145	128	50	78	51	262	85
5%	104	115	117	130	142	146	129	60	89	57	269	96
10%	107	119	121	134	146	150	133	86	117	71	287	125
15%	111	122	125	138	150	153	136	113	145	84	305	154
20%	115	126	129	142	155	157	139	139	173	98	323	182
30%	122	134	136	150	163	164	146	192	229	125	359	240
40%	129	142	144	158	171	171	152	244	285	152	395	298
50%	137	150	151	166	180	178	159	297	341	180	431	355
60%	144	157	159	173	188	185	165	349	397	207	467	413
70%	152	165	166	181	197	192	172	402	453	234	503	470
80%	159	173	174	189	205	200	179	455	509	262	539	528
90%	166	181	181	197	213	207	185	507	565	289	575	585
100%	174	188	189	205	222	214	192	560	621	316	611	643

Capacity Factor	AP 600 Nuclear	Whole Tree	Switch Grass	Municipal Solid Waste	Coal, Wood Retrofit	Solar Thermal	Solar Photo Voltaic	Wind w/CT backup	Wind w/o Backup	Landfill Gas	Pumped Storage	CAES	Adv Battery 8 hr
0%	250	162	176	589	312	233	370	40	69	198	54	44	49
1%	251	164	180	588	313	233	371	44	69	199	55	47	51
3%	252	169	189	586	315	233	373	53	69	200	58	51	55
5%	253	174	198	584	317	233	375	62	69	201	60	55	58
10%	256	186	220	578	322	233	381	83	69	203	67	66	67
15%	258	198	242	573	326	233	386	105	69	206	74	76	76
20%	261	210	264	567	331	233	391	127	69	208	81	87	85
30%	266	234	308	557	340	233	402	171	69	213	94	108	[redacted]
40%	271	258	352	546	349	[redacted]	412	214	69	218	107	129	[redacted]
50%	276	282	395	535	358	[redacted]	[redacted]	[redacted]	[redacted]	223	[redacted]	[redacted]	[redacted]
60%	281	306	439	525	367	[redacted]	[redacted]	[redacted]	[redacted]	228	[redacted]	[redacted]	[redacted]
70%	286	330	483	514	376	[redacted]	[redacted]	[redacted]	[redacted]	233	[redacted]	[redacted]	[redacted]
80%	291	354	527	503	385	[redacted]	[redacted]	[redacted]	[redacted]	238	[redacted]	[redacted]	[redacted]
90%	296	378	571	493	394	[redacted]	[redacted]	[redacted]	[redacted]	243	[redacted]	[redacted]	[redacted]
100%	301	402	615	482	403	[redacted]	[redacted]	[redacted]	[redacted]	248	[redacted]	[redacted]	[redacted]

Real - c/kWh

Capacity Factor	Neb City 600 MW	Neb City 300 MW	Greenfield 600 MW	Greenfield 300 MW	Greenfield 150 MW	Fluid Bed 200 MW	Intg Gas CC 590 MW	Gas Turbine 110 MW	LM 6000	Combined Cycle 260 MW	Ph Acid Fuel Cell	Diesel
1%	114.9	127.3	130.6	144.6	158.4	163.4	144.8	44.5	75.8	52.5	290.5	83.6
3%	38.9	43.0	44.1	48.8	53.4	55.0	48.8	18.8	29.5	19.6	99.6	32.2
5%	23.7	26.2	26.8	29.6	32.4	33.3	29.6	13.7	20.3	13.0	61.4	22.0
10%	12.2	13.5	13.8	15.3	16.7	17.1	15.2	9.9	13.3	8.1	32.7	14.3
15%	8.4	9.3	9.5	10.5	11.5	11.7	10.4	8.6	11.0	6.4	23.2	11.7
20%	6.5	7.2	7.3	8.1	8.8	8.9	8.0	7.9	9.9	5.6	18.4	10.4
30%	4.6	5.1	5.2	5.7	6.2	6.2	5.5	7.3	8.7	4.8	13.7	9.1
40%	3.7	4.0	4.1	4.5	4.9	4.9	4.3	7.0	8.1	4.4	11.3	8.5
50%	3.1	3.4	3.5	3.8	4.1	4.1	3.6	6.8	7.8	4.1	9.8	8.1
60%	2.7	3.0	3.0	3.3	3.6	3.5	3.1	6.6	7.6	3.9	8.9	7.9
70%	2.5	2.7	2.7	3.0	3.2	3.1	2.8	6.6	7.4	3.8	8.2	7.7
80%	2.3	2.5	2.5	2.7	2.9	2.8	2.5	6.5	7.3	3.7	7.7	7.5
90%	2.1	2.3	2.3	2.5	2.7	2.6	2.3	6.4	7.2	3.7	7.3	7.4
100%	2.0	2.2	2.2	2.3	2.5	2.4	2.2	6.4	7.1	3.6	7.0	7.3

Capacity Factor	AP 600 Nuclear	Whole Tree	Switch Grass	Municipal Solid Waste	Coal, Wood Retrofit	Solar Thermal	Solar Photo Voltaic	Wind w/CT backup	Wind w/o Backup	Landfill Gas	Pumped Storage	CAES	Adv Battery 8 hr
1%	286.5	187.2	205.9	671.0	357.7	266.3	423.6	50.3	78.7	226.9	62.8	53.1	58.1
3%	95.9	64.2	72.0	222.8	119.9	88.8	142.0	20.1	26.2	76.0	21.9	19.3	20.7
5%	57.8	39.6	45.2	133.2	72.4	53.3	85.7	14.1	15.7	45.8	13.8	12.6	13.3
10%	29.2	21.2	25.1	66.0	36.7	26.6	43.4	9.5	7.9	23.2	7.7	7.5	7.7
15%	19.6	15.0	18.4	43.6	24.8	17.8	29.4	8.0	5.2	15.7	5.6	5.8	5.8
20%	14.9	12.0	15.1	32.4	18.9	13.3	22.3	7.3	3.9	11.9	4.6	5.0	4.9
30%	10.1	8.9	11.7	21.2	12.9	8.9	15.3	6.5	2.6	8.1	3.6	4.1	[redacted]
40%	7.7	7.4	10.0	15.6	10.0	[redacted]	11.8	6.1	2.0	6.2	3.1	3.7	[redacted]
50%	6.3	6.4	9.0	12.2	8.2	[redacted]	[redacted]	[redacted]	[redacted]	5.1	[redacted]	[redacted]	[redacted]
60%	5.3	5.8	8.4	10.0	7.0	[redacted]	[redacted]	[redacted]	[redacted]	4.3	[redacted]	[redacted]	[redacted]
70%	4.7	5.4	7.9	8.4	6.1	[redacted]	[redacted]	[redacted]	[redacted]	3.8	[redacted]	[redacted]	[redacted]
80%	4.2	5.0	7.5	7.2	5.5	[redacted]	[redacted]	[redacted]	[redacted]	3.4	[redacted]	[redacted]	[redacted]
90%	3.8	4.8	7.2	6.3	5.0	[redacted]	[redacted]	[redacted]	[redacted]	3.1	[redacted]	[redacted]	[redacted]
100%	3.4	4.6	7.0	5.5	4.6	[redacted]	[redacted]	[redacted]	[redacted]	2.8	[redacted]	[redacted]	[redacted]

Supply Side Screening Curve Analysis

2003

Levelized - $/kW-year

Capacity Factor	Neb City 600 MW	Neb City 300 MW	Greenfield 600 MW	Greenfield 300 MW	Greenfield 150 MW	Fluid Bed 200 MW	Intg Gas CC 590 MW	Gas Turbine 110 MW	LM 6000	Combined Cycle 260 MW	Ph Acid Fuel Cell	Diesel	AP 600 Nuclear	Whole Tree	Switch Grass	Municipal Solid Waste	Coal, Wood Retrofit	Solar Thermal	Solar Photo Voltaic	Wind w/CT backup	Wind w/o Backup	Landfill Gas	Pumped Storage	CAES	Adv Battery 8 hr
0%	130	144	148	164	179	185	164	44	79	56	326	88	326	210	229	711	344	303	481	52	90	258	77	58	64
1%	131	145	149	165	180	186	165	51	86	60	331	95	326	213	235	710	345	303	483	57	90	258	79	60	66
3%	133	147	151	167	183	188	167	64	101	67	340	110	328	219	246	707	347	303	485	69	90	260	83	66	71
5%	135	149	153	169	185	190	168	78	115	74	350	125	329	226	257	705	349	303	488	80	90	261	87	72	76
10%	140	154	158	174	190	194	173	112	152	92	373	162	332	241	286	698	354	303	495	108	90	264	97	85	87
15%	144	159	162	179	196	199	177	146	188	109	396	200	336	257	314	692	360	303	502	137	90	267	107	99	99
20%	149	164	167	184	201	204	181	181	225	127	420	237	339	273	343	685	365	303	509	165	90	271	116	113	111
30%	159	174	177	195	212	213	190	249	298	163	467	312	346	304	400	672	375	303	522	222	90	277	136	141	
40%	168	184	187	205	223	222	198	317	370	198	513	387	352	335	457	659	385		536	279	90	284	155	168	
50%	178	195	197	215	234	232	207	386	443	234	560	462	359	366	514	647	395					290			
60%	187	205	206	226	245	241	215	454	516	269	607	537	365	398	571	634	405					297			
70%	197	215	216	236	256	250	224	523	589	305	654	611	372	429	628	621	415					303			
80%	207	225	226	246	266	260	232	591	662	340	700	686	379	460	685	608	425					309			
90%	216	235	236	257	277	269	241	659	734	376	747	761	385	491	742	595	435					316			
100%	226	245	245	267	288	278	249	728	807	411	794	836	392	523	800	582	445					322			

Levelized - c/kWh

Capacity Factor	Neb City 600 MW	Neb City 300 MW	Greenfield 600 MW	Greenfield 300 MW	Greenfield 150 MW	Fluid Bed 200 MW	Intg Gas CC 590 MW	Gas Turbine 110 MW	LM 6000	Combined Cycle 260 MW	Ph Acid Fuel Cell	Diesel	AP 600 Nuclear	Whole Tree	Switch Grass	Municipal Solid Waste	Coal, Wood Retrofit	Solar Thermal	Solar Photo Voltaic	Wind w/CT backup	Wind w/o Backup	Landfill Gas	Pumped Storage	CAES	Adv Battery 8 hr
1%	149.4	165.5	169.8	188.0	206.0	212.4	188.3	57.9	98.6	68.3	377.8	108.6	372.5	243.4	267.8	810.2	394.4	346.2	550.8	65.4	102.3	295.0	90.6	69.0	75.6
3%	50.5	56.0	57.3	63.4	69.5	71.5	63.4	24.5	38.4	25.5	129.5	41.9	124.7	83.5	93.6	269.1	132.2	115.4	184.7	26.1	34.1	98.8	31.7	25.1	27.0
5%	30.8	34.0	34.9	38.5	42.2	43.3	38.4	17.8	26.4	16.9	79.8	28.6	75.1	51.5	58.8	160.9	79.8	69.2	111.4	18.3	20.5	59.6	19.9	16.3	17.2
10%	15.9	17.6	18.0	19.9	21.7	22.2	19.7	12.8	17.3	10.5	42.6	18.5	37.9	27.6	32.6	79.7	40.5	34.6	56.5	12.4	10.2	30.2	11.1	9.7	10.0
15%	11.0	12.1	12.4	13.6	14.9	15.2	13.5	11.1	14.3	8.3	30.2	15.2	25.5	19.6	23.9	52.6	27.4	23.1	38.2	10.4	6.8	20.4	8.1	7.6	7.5
20%	8.5	9.4	9.5	10.5	11.5	11.6	10.3	10.3	12.8	7.3	24.0	13.5	19.3	15.6	19.6	39.1	20.8	17.3	29.0	9.4	5.1	15.5	6.6	6.5	6.3
30%	6.0	6.6	6.7	7.4	8.1	8.1	7.2	9.5	11.3	6.2	17.8	11.9	13.1	11.6	15.2	25.6	14.3	11.5	19.9	8.4	3.4	10.5	5.2	5.4	
40%	4.8	5.3	5.3	5.8	6.4	6.3	5.7	9.1	10.6	5.7	14.7	11.0	10.0	9.6	13.0	18.8	11.0		15.3	8.0	2.6	8.1	4.4	4.8	
50%	4.1	4.4	4.5	4.9	5.3	5.3	4.7	8.8	10.1	5.3	12.8	10.5	8.2	8.4	11.7	14.8	9.0					6.6			
60%	3.6	3.9	3.9	4.3	4.7	4.6	4.1	8.6	9.8	5.1	11.5	10.2	7.0	7.6	10.9	12.1	7.7					5.6			
70%	3.2	3.5	3.5	3.8	4.2	4.1	3.6	8.5	9.6	5.0	10.7	10.0	6.1	7.0	10.2	10.1	6.8					4.9			
80%	2.9	3.2	3.2	3.5	3.8	3.7	3.3	8.4	9.4	4.9	10.0	9.8	5.4	6.6	9.8	8.7	6.1					4.4			
90%	2.7	3.0	3.0	3.3	3.5	3.4	3.1	8.4	9.3	4.8	9.5	9.7	4.9	6.2	9.4	7.5	5.5					4.0			
100%	2.6	2.8	2.8	3.0	3.3	3.2	2.8	8.3	9.2	4.7	9.1	9.5	4.5	6.0	9.1	6.6	5.1					3.7			
Levelization Factor	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.300	1.207	1.102	1.300	1.300	1.300	1.300	1.300	1.444	1.300	1.300

Busbar Costs By Component

Real - cents/kWh

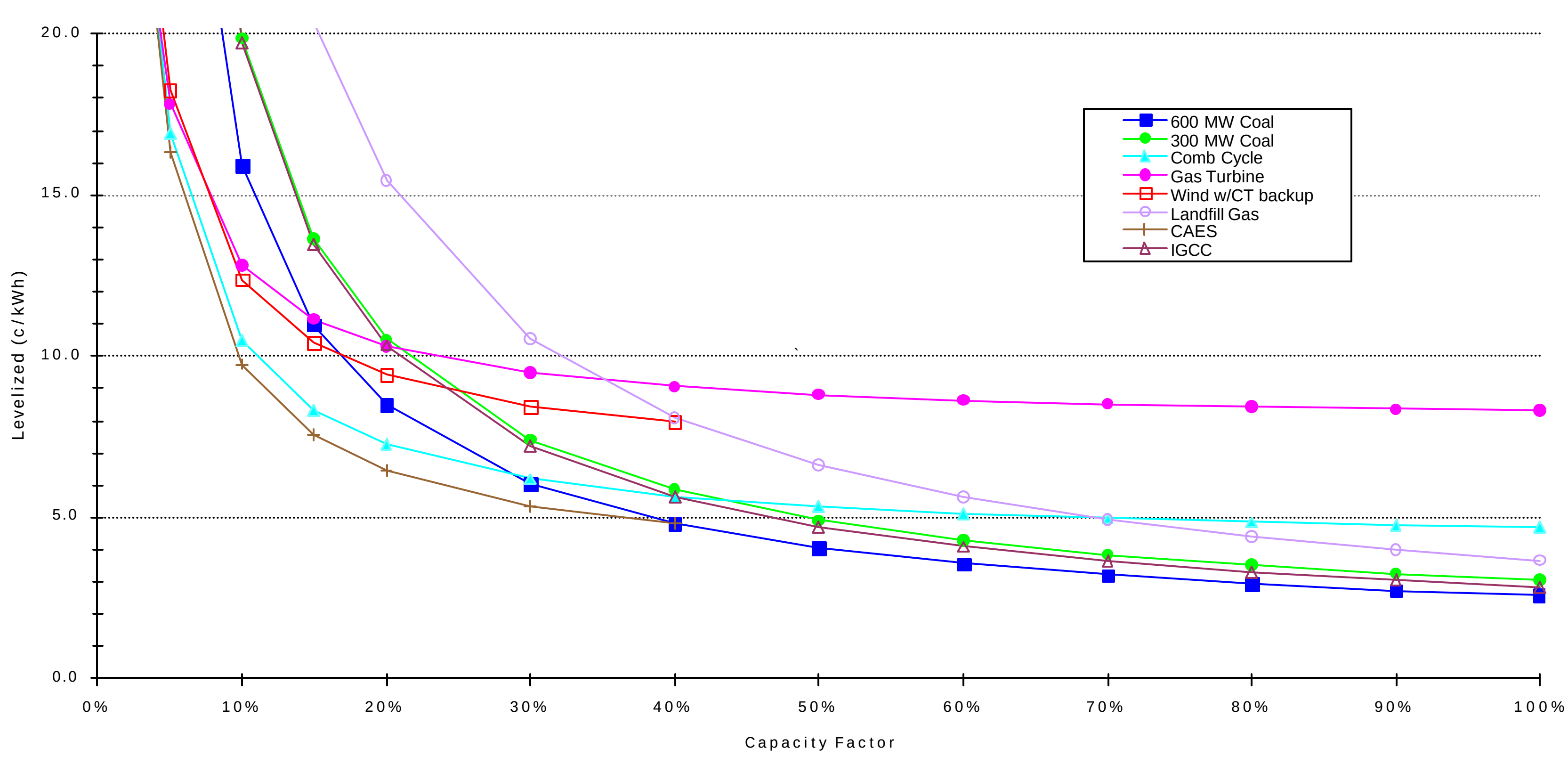
	Neb City 600 MW	Neb City 300 MW	Greenfield 600 MW	Greenfield 300 MW	Greenfield 150 MW	Fluid Bed 200 MW	Intg Gas CC 590 MW	Gas Turbine 110 MW	LM 6000	Combined Cycle 260 MW	Ph Acid Fuel Cell	Diesel	AP 600 Nuclear	Whole Tree	Switch Grass	Municipal Solid Waste	Coal, Wood Retrofit	Solar Thermal	Solar Photo Voltaic	Wind w/CT backup	Wind w/o Backup	Landfill Gas	Pumped Storage	CAES	Adv Battery 8 hr
Capacity	78.0	82.8	89.7	95.3	99.0	108.2	95.4	26.3	46.9	37.0	271.5	46.1	179.9	115.9	144.2	463.6	349.3	193.7	406.1	30.9	52.9	99.7	54.8	42.8	53.7
Fixed O&M	36.1	43.6	40.0	48.3	58.4	54.4	48.7	12.2	22.5	12.4	14.9	30.9	106.0	68.5	56.8	208.6	7.4	72.6	16.3	14.5	25.8	126.7	6.4	7.9	2.4
Variable	0.8	0.9	0.9	0.9	1.0	0.8	0.7	6.0	6.4	3.1	4.1	6.6	0.6	2.7	5.0	-1.2	1.0	0.0	1.2	5.0	0.0	0.6	1.5	2.4	2.1
Total - 1% CF	114.9	127.3	130.6	144.6	158.4	163.4	144.8	44.5	75.8	52.5	290.5	83.6	286.5	187.2	205.9	671.0	357.7	266.3	423.6	50.3	78.7	226.9	62.8	53.1	58.1
Capacity	15.6	16.6	17.9	19.1	19.8	21.6	19.1	5.3	9.4	7.4	54.3	9.2	36.0	23.2	28.8	92.7	69.9	38.7	81.2	6.2	10.6	19.9	11.0	8.6	10.7
O&M	7.2	8.7	8.0	9.7	11.7	10.9	9.7	2.4	4.5	2.5	3.0	6.2	21.2	13.7	11.4	41.7	1.5	14.5	3.3	2.9	5.2	25.3	1.3	1.6	0.5
Fuel	0.8	0.9	0.9	0.9	1.0	0.8	0.7	6.0	6.4	3.1	4.1	6.6	0.6	2.7	5.0	-1.2	1.0	0.0	1.2	5.0	0.0	0.6	1.5	2.4	2.1
Total - 5% CF	23.7	26.2	26.8	29.6	32.4	33.3	29.6	13.7	20.3	13.0	61.4	22.0	57.8	39.6	45.2	133.2	72.4	53.3	85.7	14.1	15.7	45.8	13.8	12.6	13.3
Capacity	3.2	3.4	3.7	4.0	4.1	4.5	4.0	1.1	2.0	1.5	11.3	1.9	7.5	4.8	6.0	19.3	14.5	8.1	16.9	1.3	2.2	4.1	2.3	1.8	
O&M	1.5	1.8	1.7	2.0	2.4	2.3	2.0	0.5	0.9	0.5	0.6	1.3	4.4	2.9	2.4	8.7	0.3	3.0	0.7	0.6	1.1	5.3	0.3	0.3	
Fuel	0.8	0.9	0.9	0.9	1.0	0.8	0.7	6.0	6.4	3.1	4.1	6.6	0.6	2.7	5.0	-1.2	1.0	0.0	1.2	5.0	0.0	0.6	1.5	2.4	
Total - 24% CF	5.6	6.1	6.3	6.9	7.5	7.6	6.7	7.6	9.3	5.2	16.0	9.8	12.5	10.4	13.4	26.8	15.9	11.1	18.8	6.9	3.3	10.0	4.1	4.5	
Capacity	2.2	2.3	2.5	2.6	2.7	3.0	2.6	0.7	1.3	1.0	7.5	1.3	5.0	3.2	4.0	12.9	9.7		11.3	0.9	1.5	2.8	1.5	1.2	
O&M	1.0	1.2	1.1	1.3	1.6	1.5	1.4	0.3	0.6	0.3	0.4	0.9	2.9	1.9	1.6	5.8	0.2		0.5	0.4	0.7	3.5	0.2	0.2	
Fuel	0.8	0.9	0.9	0.9	1.0	0.8	0.7	6.0	6.4	3.1	4.1	6.6	0.6	2.7	5.0	-1.2	1.0		1.2	5.0	0.0	0.6	1.5	2.4	
Total - 36% CF	4.0	4.4	4.5	4.9	5.3	5.3	4.7	7.1	8.3	4.5	12.1	8.7	8.5	7.9	10.6	17.4	10.9		12.9	6.2	2.2	6.8	3.2	3.8	
Capacity	1.3	1.4	1.5	1.6	1.7	1.8	1.6	0.4	0.8	0.6	4.5	0.8	3.0	1.9	2.4	7.7	5.8					1.7			
O&M	0.6	0.7	0.7	0.8	1.0	0.9	0.8	0.2	0.4	0.2	0.2	0.5	1.8	1.1	0.9	3.5	0.1					2.1			
Fuel	0.8	0.9	0.9	0.9	1.0	0.8	0.7	6.0	6.4	3.1	4.1	6.6	0.6	2.7	5.0	-1.2	1.0					0.6			
Total - 60% CF	2.7	3.0	3.0	3.3	3.6	3.5	3.1	6.6	7.6	3.9	8.9	7.9	5.3	5.8	8.4	10.0	7.0					4.3			
Capacity	0.9	1.0	1.1	1.1	1.2	1.3	1.1	0.3	0.6	0.4	3.2	0.5	2.1	1.4	1.7	5.5	4.1					1.2			
O&M	0.4	0.5	0.5	0.6	0.7	0.6	0.6	0.1	0.3	0.1	0.2	0.4	1.2	0.8	0.7	2.5	0.1					1.5			
Fuel	0.8	0.9	0.9	0.9	1.0	0.8	0.7	6.0	6.4	3.1	4.1	6.6	0.6	2.7	5.0	-1.2	1.0					0.6			
Total - 85% CF	2.2	2.4	2.4	2.6	2.8	2.7	2.4	6.5	7.2	3.7	7.5	7.5	3.9	4.9	7.4	6.7	5.2					3.2			

Busbar Costs By Component

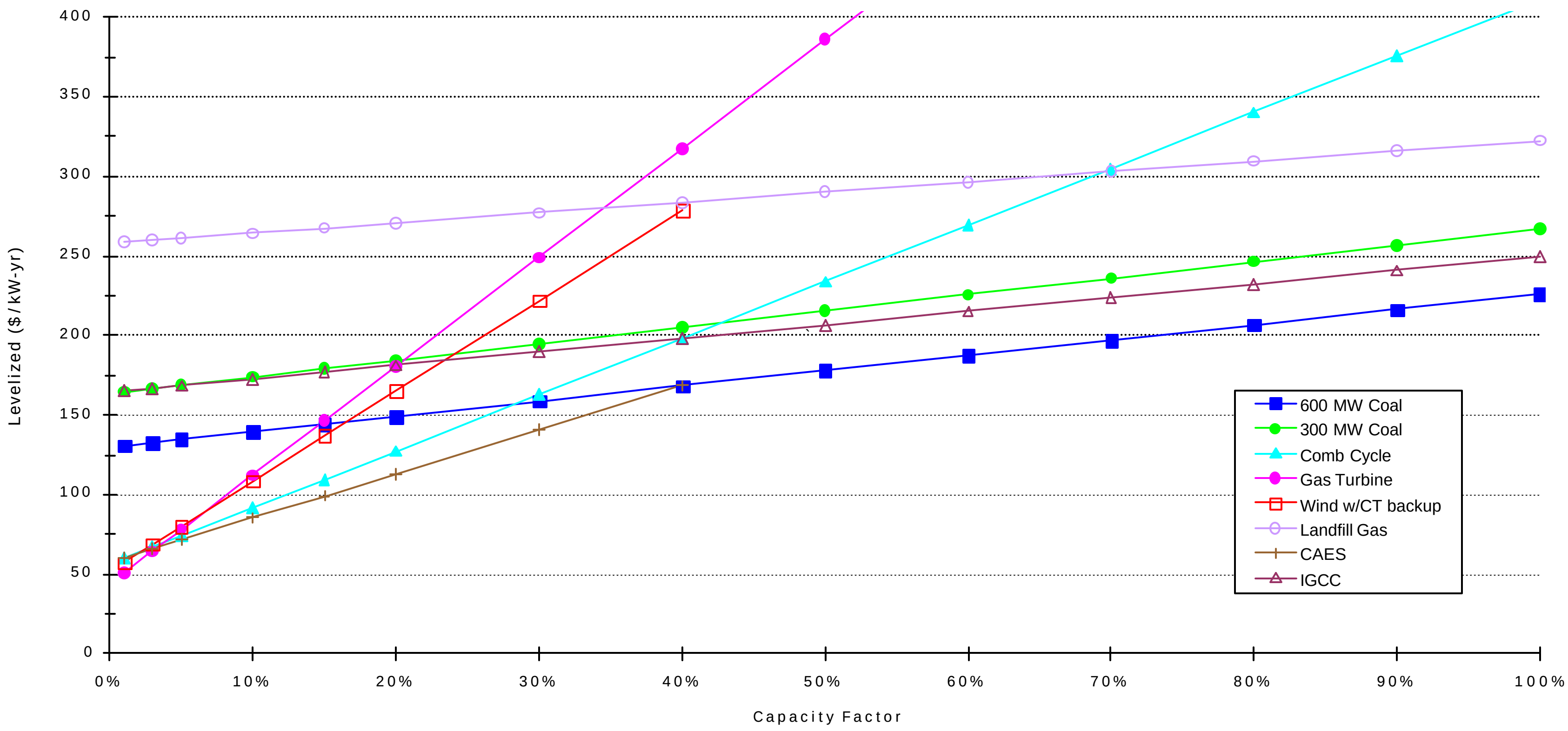
Levelized - cents/kWh

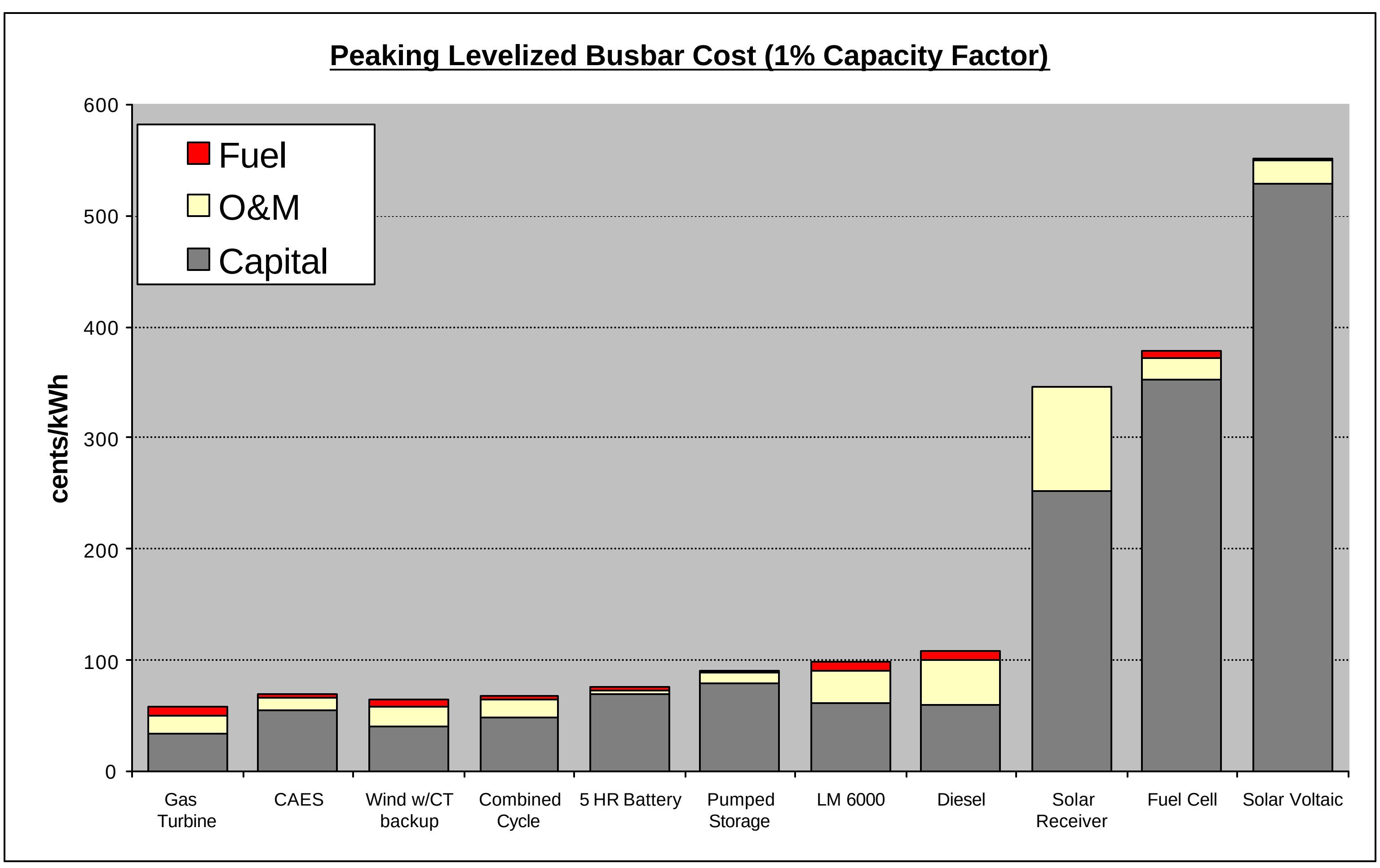
	Neb City 600 MW	Neb City 300 MW	Greenfield 600 MW	Greenfield 300 MW	Greenfield 150 MW	Fluid Bed 200 MW	Intg Gas CC 590 MW	Gas Turbine 110 MW	LM 6000	Combined Cycle 260 MW	Ph Acid Fuel Cell	Diesel	AP 600 Nuclear	Whole Tree	Switch Grass	Municipal Solid Waste	Coal, Wood Retrofit	Solar Thermal	Solar Photo Voltaic	Wind w/CT backup	Wind w/o Backup	Landfill Gas	Pumped Storage	CAES	Adv Battery 8 hr
Capacity	101.4	107.7	116.7	124.0	128.8	140.7	124.0	34.3	61.0	48.1	353.0	59.9	233.9	150.8	187.5	559.8	385.0	251.8	528.1	40.1	68.8	129.6	79.1	55.6	69.8
Fixed O&M	46.9	56.7	52.0	62.8	75.9	70.7	63.4	15.8	29.2	16.1	19.4	40.2	137.9	89.1	73.8	251.9	8.2	94.4	21.2	18.8	33.6	164.7	9.3	10.3	3.1
Variable	1.1	1.2	1.1	1.2	1.2	1.1	1.0	7.8	8.3	4.1	5.3	8.5	0.8	3.6	6.5	-1.5	1.1	0.0	1.6	6.5	0.0	0.7	2.2	3.2	2.7
Total - 1% CF	149.4	165.5	169.8	188.0	206.0	212.4	188.3	57.9	98.6	68.3	377.8	108.6	372.5	243.4	267.8	810.2	394.4	346.2	550.8	65.4	102.3	295.0	90.6	69.0	75.6
Capacity	20.3	21.5	23.3	24.8	25.8	28.1	24.8	6.9	12.2	9.6	70.6	12.0	46.8	30.2	37.5	112.0	77.0	50.4	105.6	8.0	13.8	25.9	15.8	11.1	14.0
O&M	9.4	11.3	10.4	12.6	15.2	14.1	12.7	3.2	5.8	3.2	3.9	8.0	27.6	17.8	14.8	50.4	1.6	18.9	4.2	3.8	6.7	32.9	1.9	2.1	0.6
Fuel	1.1	1.2	1.1	1.2	1.2	1.1	1.0	7.8	8.3	4.1	5.3	8.5	0.8	3.6	6.5	-1.5	1.1	0.0	1.6	6.5	0.0	0.7	2.2	3.2	2.7
Total - 5% CF	30.8	34.0	34.9	38.5	42.2	43.3	38.4	17.8	26.4	16.9	79.8	28.6	75.1	51.5	58.8	160.9	79.8	69.2	111.4	18.3	20.5	59.6	19.9	16.3	17.2
Capacity	4.2	4.5	4.9	5.2	5.4	5.9	5.2	1.4	2.5	2.0	14.7	2.5	9.7	6.3	7.8	23.3	16.0	10.5	22.0	1.7	2.9	5.4	3.3	2.3	[redacted]
O&M	2.0	2.4	2.2	2.6	3.2	2.9	2.6	0.7	1.2	0.7	0.8	1.7	5.7	3.7	3.1	10.5	0.3	3.9	0.9	0.8	1.4	6.9	0.4	0.4	[redacted]
Fuel	1.1	1.2	1.1	1.2	1.2	1.1	1.0	7.8	8.3	4.1	5.3	8.5	0.8	3.6	6.5	-1.5	1.1	0.0	1.6	6.5	0.0	0.7	2.2	3.2	[redacted]
Total - 24% CF	7.3	8.0	8.1	9.0	9.8	9.9	8.8	9.9	12.1	6.7	20.8	12.7	16.2	13.5	17.4	32.3	17.5	14.4	24.4	8.9	4.3	13.0	5.9	5.9	[redacted]
Capacity	2.8	3.0	3.2	3.4	3.6	3.9	3.4	1.0	1.7	1.3	9.8	1.7	6.5	4.2	5.2	15.5	10.7	[redacted]	14.7	1.1	1.9	3.6	2.2	1.5	[redacted]
O&M	1.3	1.6	1.4	1.7	2.1	2.0	1.8	0.4	0.8	0.4	0.5	1.1	3.8	2.5	2.0	7.0	0.2	[redacted]	0.6	0.5	0.9	4.6	0.3	0.3	[redacted]
Fuel	1.1	1.2	1.1	1.2	1.2	1.1	1.0	7.8	8.3	4.1	5.3	8.5	0.8	3.6	6.5	-1.5	1.1	[redacted]	1.6	6.5	0.0	0.7	2.2	3.2	[redacted]
Total - 36% CF	5.2	5.7	5.8	6.4	6.9	6.9	6.2	9.2	10.8	5.8	15.7	11.3	11.1	10.2	13.8	21.1	12.1	[redacted]	16.8	8.1	2.8	8.9	4.7	5.0	[redacted]
Capacity	1.7	1.8	1.9	2.1	2.1	2.3	2.1	0.6	1.0	0.8	5.9	1.0	3.9	2.5	3.1	9.3	6.4	[redacted]	[redacted]	[redacted]	[redacted]	2.2	[redacted]	[redacted]	[redacted]
O&M	0.8	0.9	0.9	1.0	1.3	1.2	1.1	0.3	0.5	0.3	0.3	0.7	2.3	1.5	1.2	4.2	0.1	[redacted]	[redacted]	[redacted]	[redacted]	2.7	[redacted]	[redacted]	[redacted]
Fuel	1.1	1.2	1.1	1.2	1.2	1.1	1.0	7.8	8.3	4.1	5.3	8.5	0.8	3.6	6.5	-1.5	1.1	[redacted]	[redacted]	[redacted]	[redacted]	0.7	[redacted]	[redacted]	[redacted]
Total - 60% CF	3.6	3.9	3.9	4.3	4.7	4.6	4.1	8.6	9.8	5.1	11.5	10.2	7.0	7.6	10.9	12.1	7.7	[redacted]	[redacted]	[redacted]	[redacted]	5.6	[redacted]	[redacted]	[redacted]
Capacity	1.2	1.3	1.4	1.5	1.5	1.7	1.5	0.4	0.7	0.6	4.2	0.7	2.8	1.8	2.2	6.6	4.5	[redacted]	[redacted]	[redacted]	[redacted]	1.5	[redacted]	[redacted]	[redacted]
O&M	0.6	0.7	0.6	0.7	0.9	0.8	0.7	0.2	0.3	0.2	0.2	0.5	1.6	1.0	0.9	3.0	0.1	[redacted]	[redacted]	[redacted]	[redacted]	1.9	[redacted]	[redacted]	[redacted]
Fuel	1.1	1.2	1.1	1.2	1.2	1.1	1.0	7.8	8.3	4.1	5.3	8.5	0.8	3.6	6.5	-1.5	1.1	[redacted]	[redacted]	[redacted]	[redacted]	0.7	[redacted]	[redacted]	[redacted]
Total - 85% CF	2.8	3.1	3.1	3.4	3.7	3.5	3.2	8.4	9.4	4.8	9.7	9.7	5.1	6.4	9.6	8.1	5.8	[redacted]	[redacted]	[redacted]	[redacted]	4.2	[redacted]	[redacted]	[redacted]

Screening Curve Analysis

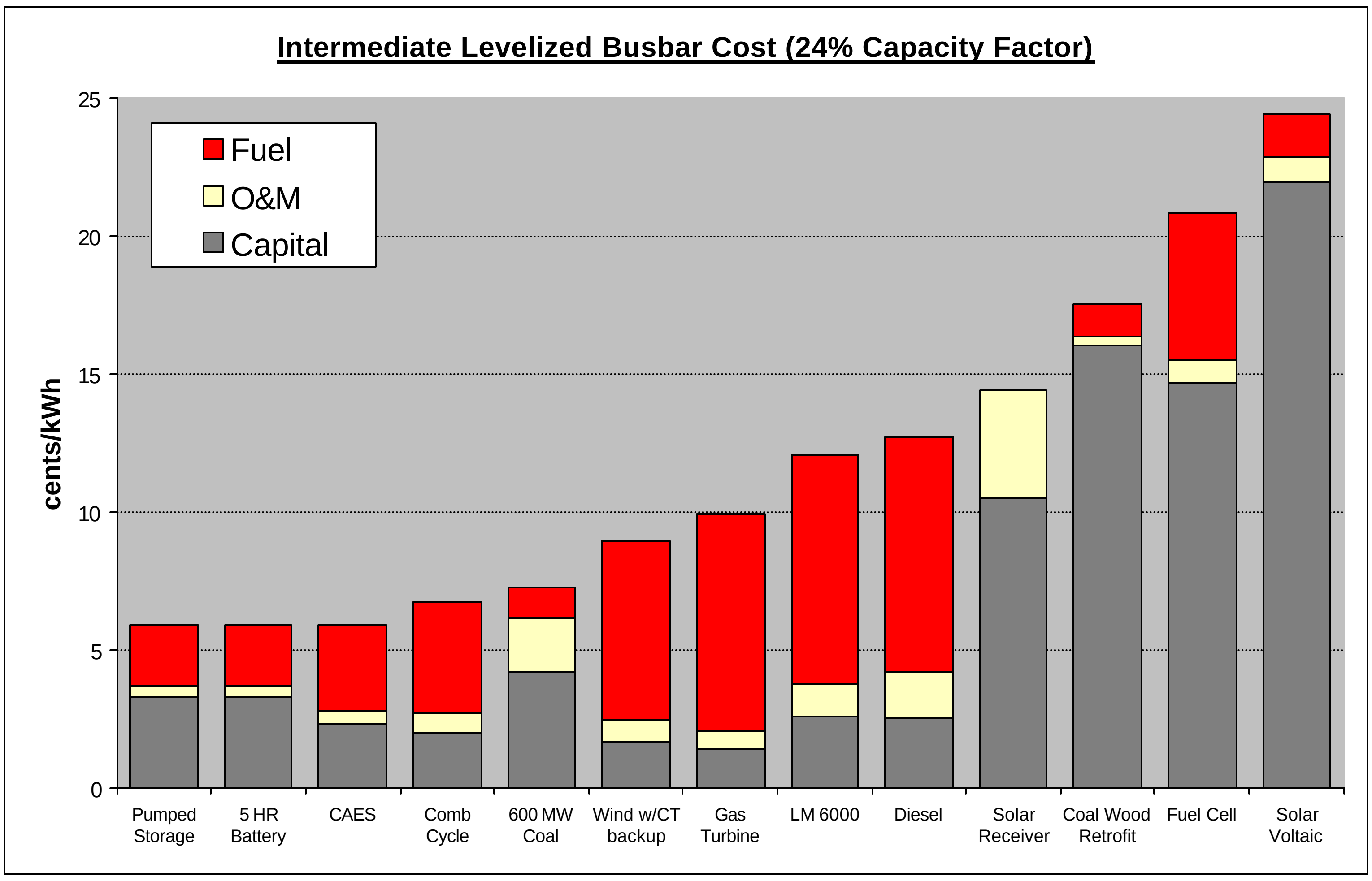


Screening Curve Analysis

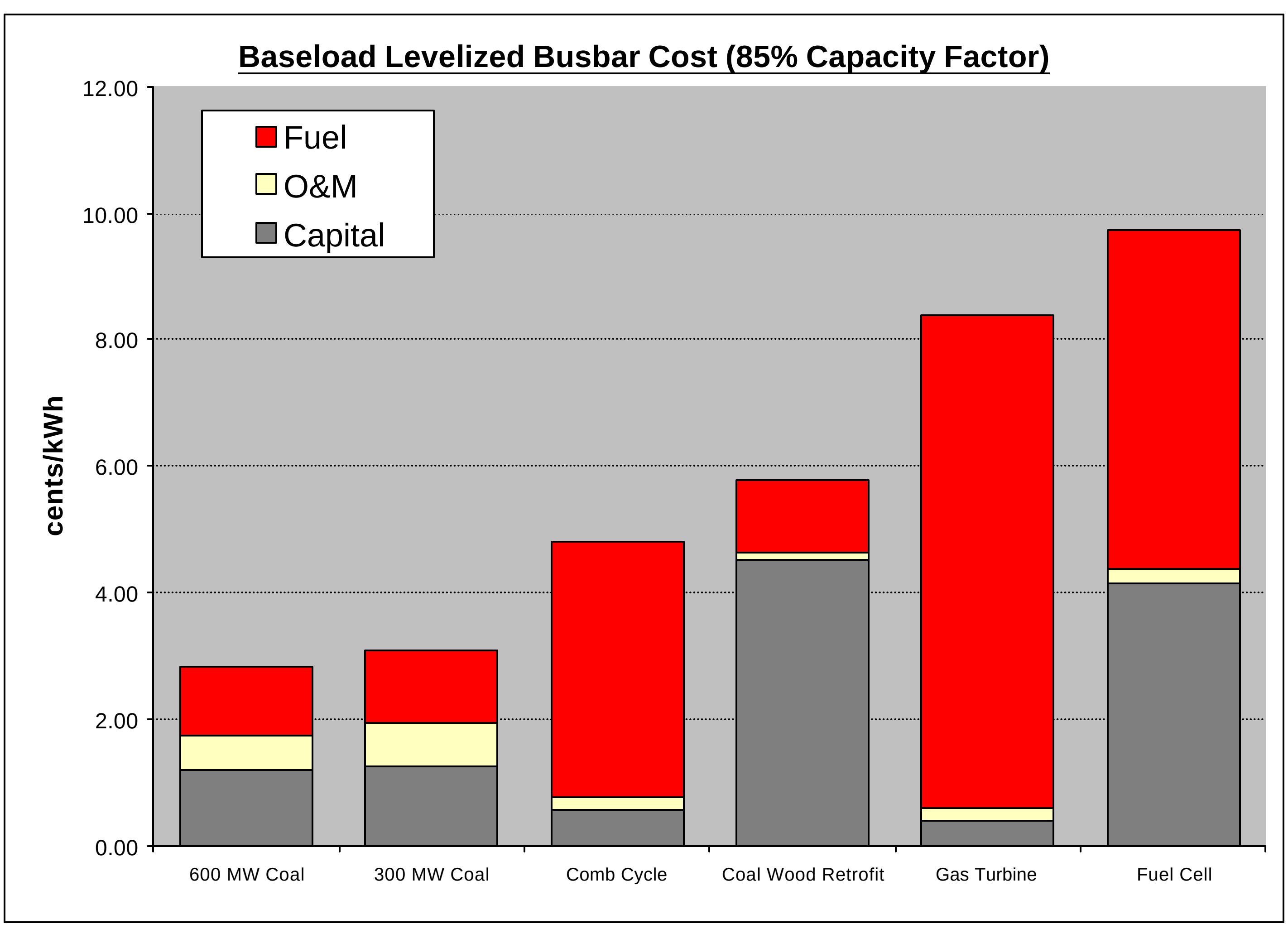




c/kWh	Gas Turbine	CAES	Wind w/CT backup	Combined Cycle	5 HR Battery	Pumped Storage	LM 6000	Diesel	Solar Receiver	Fuel Cell	Solar Voltaic
Capital	34.26	55.63	40.12	48.08	69.82	79.14	61.04	59.89	251.84	353.02	528.05
O&M	15.82	10.26	18.84	16.14	3.08	9.27	29.23	40.21	94.37	19.41	21.22
Fuel	7.81	3.16	6.48	4.05	2.67	2.22	8.31	8.54	0.00	5.34	1.56
TOTAL	57.89	69.05	65.44	68.27	75.57	90.63	98.58	108.64	346.22	377.76	550.83



c/kWh	Pumped Storage	5 HR Battery	CAES	Comb Cycle	600 MW Coal	Wind w/CT backup	Gas Turbine	LM 6000	Diesel	Solar Receiver	Coal Wood Retrofit	Fuel Cell	Solar Voltaic
Capital	3.29	3.29	2.31	2.00	4.22	1.67	1.43	2.54	2.49	10.48	16.02	14.69	21.97
O&M	0.39	0.39	0.43	0.67	1.95	0.78	0.66	1.22	1.67	3.93	0.34	0.81	0.88
Fuel	2.22	2.22	3.16	4.05	1.09	6.48	7.81	8.31	8.54	0.00	1.15	5.34	1.56
TOTAL	5.89	5.89	5.90	6.72	7.27	8.93	9.89	12.07	12.70	14.41	17.51	20.84	24.42



c/kWh	600 MW Coal	300 MW Coal	Comb Cycle	Coal Wood Retrofit	Gas Turbine	Fuel Cell
Capital	1.19	1.27	0.57	4.53	0.40	4.15
O&M	0.55	0.67	0.19	0.10	0.19	0.23
Fuel	1.09	1.15	4.05	1.15	7.81	5.34
TOTAL	2.84	3.09	4.81	5.77	8.40	9.72