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Integrated Resource Plan

Nebraska Public Power District

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EXECUTIVE SUMMARY

Introduction

Nebraska Public Power District (NPPD) is Nebraska's largest electric generating utility, with a chartered territory including all or parts of 91 of the state's 93 counties. NPPD serves the total wholesale power requirements of 52 municipalities and 24 public power districts and cooperatives. NPPD also serves 80 municipalities at retail totaling nearly 88,000 customers. More than 5,000 miles of power lines make up the NPPD electrical grid system, including transmission and subtransmission lines.

NPPD uses a mix of generating facilities, including nuclear, coal, oil, and natural gas, fueled resources. NPPD also generates electricity from renewable resources utilizing wind and hydro-power (water). NPPD also purchases electricity from the Western Area Power Administration (WAPA), which is a marketing and transmission agency for Federal hydropower.

Integrated resource planning includes the combined development of electricity supply options and demand side management options (efficiency, conservation, and demand response) resulting in a least cost plan for providing energy services to NPPD's customers over the study period (2008 – 2027). This least cost approach to resource planning includes consideration for some environmental costs and assesses risk associated with the various planning options. Integrated resource planning is an ongoing process that must be flexible enough to respond to changes in the business environment.

NPPD's Integrated Resource Plan (IRP) provides insight as to the most favorable approach for adding resources to meet future native load requirements while minimizing cost and risk. The IRP does not provide an exact expansion plan to be followed for the next 20 years. Nor does it evaluate every possible combination of resources to meet future native load requirements. The IRP is intended to provide a "directionally correct" vision of the future for decision making. While the modeling employed is intended to be accurate and comprehensive, it is also intended to support and not replace the judgment of NPPD's decision makers.

IRP Planning Principles

The IRP must align with NPPD's Vision, Mission, and Strategic Plan. Key objectives from NPPD's Strategic Plan that serve as guiding principles for the IRP process include:

- NPPD will have a diverse power resource mix, consisting of owned facilities and contract purchases, sufficient to meet loads under extreme weather conditions.
- NPPD will evaluate all forms of renewable resources feasible in Nebraska and incorporate them in the total mix of NPPD-owned generation and contract purchases, with a goal of achieving 10% of our energy supply for NPPD's native load from renewable resources by 2020.
- NPPD will strive to increase energy efficiency, support effective economic development that enhances NPPD's load profile, and provide services that are in alignment with

NPPD's core business to broaden NPPD's revenue base and reduce overall overhead costs to our customers.

Some general guidelines that were used to help focus the IRP analysis process are:

- Resource expansion plans evaluated and selected in the IRP must meet future native load requirements.
- Resource expansion plans evaluated and selected in the IRP should minimize cost on a long-term basis after considering the effects of various risk factors.
- The IRP should avoid risks associated with investing in resources that do not perform well under a range of future planning scenarios.
- The IRP should focus additional attention to resources that function well under a range of future planning scenarios.
- The IRP should address near term resource needs and position NPPD for the future.
- The IRP must meet the requirements of applicable Nebraska Statutes, WAPA, and NPPD's Wholesale Power Contracts.

Interface with the Public

NPPD used a multi-faceted approach to communicate with our customers and other stakeholders. This approach is designed to provide for multiple opportunities to educate our customer base and obtain feedback on the IRP process and the various options being considered. The process included meetings with the NPPD Board of Directors, meetings with customer groups, meetings with interested third parties, and dedicating a portion of NPPD's corporate public website to IRP communication (http://www.nppd.com/irp/). Comments received throughout the public input process have been addressed and incorporated into the IRP as appropriate.

Existing System & Committed Resources

Generation

NPPD uses a diverse mix of generation resources, including coal, nuclear, natural gas, diesel oil, hydro, and wind to meet the needs of its customers. For 2007 approximately 57% of NPPD's energy generation was from coal, 24% nuclear, 3% hydro, 4% gas & oil, and 1% wind. The remaining 11% of NPPD's energy was supplied through purchases with over ½ of the purchases coming from WAPA. Appendix B lists all of NPPD's existing generation resources, including in-state hydro purchases and peaking capacity purchases.

In addition to the existing capacity, NPPD is a participant in Omaha Public Power District's (OPPD's) Nebraska City Unit 2 project (157 MW), which is scheduled for commercial operation starting in 2009. NPPD has executed or is in negotiation for Power Purchase Agreements (PPAs) with private wind developers that will provide between 10 MW and 26 MW of accredited (60 MW and 150 MW nameplate) renewable wind capacity starting in 2009. NPPD is also expecting 60 MW of cogeneration capability to be added by a major ethanol producer in NPPD's service territory in the 2009 – 2010 timeframe. Additionally, NPPD will recapture 570 MW of generation capability as participation contracts for portions of CNS and GGS capacity

expire between now and 2014. NPPD's diverse mix of generation resources combined with the new generation capability additions ensure that NPPD will have adequate resources to provide reliable electric service to its customers in the near future.

Transmission

NPPD's transmission system includes nearly 4,300 miles of transmission lines in the state of Nebraska. This is comprised of 896 miles of 345 kV, 683 miles of 230 kV and 2,713 miles of 115 kV facilities. The NPPD control area encompasses a significant portion of the state of Nebraska and also includes transmission facilities owned by Grand Island, Hastings, Tri-State, and WAPA. The NPPD system is characterized by summer peak air conditioning and irrigation loads, extreme seasonal load level variations, western Nebraska stability limitations, and four regional constrained transmission interfaces.

One of many inputs required by Transmission Planning when reviewing the reliability of the transmission system for a new unit is its location. Since this IRP did not go into the detail of location for most of the new resources, a well defined scope of what is needed for transmission is not available. However, to evaluate supply side resources, all costs, including transmission should be included. To support this evaluation, transmission estimates were included, based on industry estimates, engineering judgment, and/or recently installed projects. Transmission capital costs are usually on an order of magnitude less than the capital costs of the generating unit, thus the impact of transmission cost uncertainty on the IRP results is not deemed to be as great as other variables.

Load Forecast

NPPD employs both top-down and bottom-up forecasting methods. The top-down, or comprehensive forecast uses service area socioeconomic "drivers" to project loads based on overall service area economic and demographic trends. The comprehensive forecast includes models for NPPD system level demand and energy at the Busbar, or system inlet. The comprehensive forecast also develops customer class energy forecasts at the end-use meter level. The bottom-up or distributor level forecast consists of producing monthly demand and energy forecasts for all of NPPD's wholesale distributors, including NPPD Retail. The distributor level forecast uses data at Bus A, the metering point for wholesale billing. The two methods are reconciled by losses so that Busbar, Bus A, and meter level forecasts are consistent with each other.

The load forecast used in the IRP analysis assumes that NPPD's summer demand requirements will grow at an average rate of 3.6% annually between 2008 and 2013, and the demand requirements are forecasted to grow at an average rate of 1.4% annually between 2014 and 2027[1]. NPPD's energy requirements are forecasted to grow at an average rate of 4.6% annually between 2008 and 2013, and the energy requirements are forecasted to grow at an average rate of 1.7% annually between 2014 and 2027.

[1] Corresponding winter season demand requirements are forecast to grow at an average rate of 4.0% between 2008/09 and 2013/14, and 1.7% annually between 2014/15 and 2027/28.

Major Planning Assumptions

Environmental

The IRP process is not geared to detailed consideration of each and every environmental issue relating to water, air quality, hazardous waste, wildlife, and other societal concerns. Rather, it makes the assumption that there will be ways to deal with the smaller issues in due course; although, all issues will ultimately need resolution. The focus of this study and report is on certain air emissions from the resources; namely carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg), with particular emphasis on CO_2.

The general industry consensus appears to be that making plans to prepare for the possibility of greenhouse gas regulation (CO_2 is the major greenhouse gas) is appropriate. Further, that complying with such a regulation will be a very large task that needs many diverse contributions in order to affect a solution. The expansion plans analyzed in this study and described in Section 8.4 have considered diversity by using several resource alternatives, each contributing what it can to the CO_2 regulation scenarios.

Major IRP assumptions for CO_2 regulation are:

- The regulations will be enacted between 2012 and 2014,
- The regulations will create a cap and trade program with decreasing free allowances over time,
- The costs will range initially from $6 to $30 / metric ton to $19 to $92 / metric ton in 2027, all in nominal dollars, and
- The cap and trade market system will always have allowances and/or certified offset credits available for purchase at some cost. This particular assumption has large significance in terms of risk and was found to warrant further consideration as part of the Action Plan.

Renewable Portfolio Standard (RPS)

Potential future state or national RPS regulation could have significant impact on NPPD's future generation choices. A RPS could be viewed as complementary to greenhouse gas regulation, because both accomplish some of the same goals. The planning process for renewable generation resources needs to consider the possibilities and issues associated with potentially needing to comply with an RPS, especially because oftentimes RPS legislation does not provide much lead time for facility approval and installation.

The general industry consensus appears to be that making plans that prepare for the possibility of greenhouse gas regulation is appropriate, and renewable generation is one of the potential solutions, with or without an RPS regulation. Wind generation is expected to be the largest contributor to renewable energy development. However, other renewable sources are also included in the expansion plans and examined as well. Although it is not certain which, if any, potential RPS will come to pass, the study ranges for RPS included in the IRP generally account for the expected variation in this uncertainty.

Major IRP assumptions for RPS requirements are:

- Low case– 5% of native load
- Medium case (based on legislation introduced in Nebraska in 2007)– 10% by 2019
- High case (based on RPS requirements in nearby states) – 30% by 2025

Capital and O&M Costs of New Units

The IRP used a number of sources in developing the cost and performance assumptions for future unit alternatives, including: Electric Power Research Institute (EPRI), Rocky Mountain Institute (RMI), Northwest Power and Conservation Council (NPCC), as well as recently completed projects by NPPD and others. Differing price ranges were considered for the different resource types. The price range differences between the various options are more critical than the absolute price range in measuring the relative risk of each option. O&M costs were also modeled with price ranges.

The smallest price ranges for capital costs are for gas-fired combustion turbines and combined cycle plants since these technologies are mature and there have been a number of utility installations over the past few years. The range assumed was from a -10% to a +15% difference from the base assumptions. Wind, biomass, and coal units without carbon capture had a slightly larger range, -10% to +20%. Nuclear, pumped hydro storage, and coal units with carbon capture were larger yet (-10% to +30%) due to either being an immature technology or the absence of units recently built. Solar had the largest range since the base cost assumed that the capital cost for solar would drop considerably from today's cost based on its technology maturity. Solar resources are assumed to have a capital cost range from -10% of base to +50% of base.

Fuel and Market Prices

In general, fuel and market prices are based on assumptions from NPPD's latest rate track period, which extends to 2013. For fuel prices beyond this period, assumptions from the Global Energy Decision's (GED) market forecast NPPD subscribes to were generally used, with minor adjustments made to correlate to the Fuel Department's fuel forecast. The Fuel Department was also consulted in the development of the high and low fuel ranges.

The electricity market is tied very closely to the fuel market. The market forecast for the IRP model was based on GED's market forecast, and was then adjusted based on the fuel prices above. In general, the electricity market was correlated to the natural gas market during on-peak periods, coal prices during the off-peak periods, and the long-term prices were reviewed such that they would generally follow the busbar costs for new units.

Major IRP assumptions for fuel costs are:

- Costs follow NPPD's rate track assumptions and then escalate from 2.3% to 3.8% per year beyond 2013.
- Coal: $9 to $14 / MWh in 2008; $15 to $40 / MWh in 2027
- Nuclear: $6 to $7 / MWh in 2008; $10 to $19 / MWh in 2027
- Natural Gas Combined Cycle: $47 to $91 / MWh in 2008; $58 to $158 / MWh in 2027

Major IRP assumptions for the 7x24 electricity market are:

- $40 to $62 / MWh in 2008
- $59 to $99 / MWh in 2027

Resources Studied

Energy Efficiency, Conservation, and Demand Response

An alternative to building additional supply-side (generation and delivery) resources to meet higher demands is to affect end-use customer behavior changes that result in reductions in their specific energy related requirements. These reductions can be achieved through improved energy efficiency, energy conservation, and reduced demand for energy.

NPPD presently has a very successful demand response program, called the demand waiver program, to reduce summer billable peaks. The majority of savings in this program is due to irrigation load control by various wholesale customers, which accounted for approximately 515 MW of demand reduction in 2007. Another 57 MW of demand reduction was realized in 2007 from the Energy Curtailment Program (45 MW) and other sources (12 MW).

NPPD contracted with Summit Blue Consulting, LLC to develop additional Demand Side Management (DSM) programs to be implemented by NPPD starting in 2008. The results of the Summit Blue Study were used to validate the energy efficiency assumptions used in the IRP.

Major IRP assumptions for energy efficiency are:

- Cumulative energy savings: 0.03% to 0.15% of annual energy use (5 GWh to 20 GWh, respectively) in 2008 to 1.6% to 8.9% of annual energy use (335 GWh to 1,865 GWh, respectively) in 2027
- Cumulative demand savings: 0.02% to 0.12% of billable peak demand (0.6 MW to 3 MW, respectively) in 2008 to 1.6% to 9.2% of billable peak demand (60 MW to 333 MW, respectively) in 2027
- Annual cost to achieve savings above (2008 $): $1M to $5M in 2008 to $3M to $60M in 2027 (real dollars)

Renewable

Renewable projects include wind, solar, biomass, landfill gas, and new or incremental hydro facilities. The amount of additional generation available to NPPD from landfill gas or new hydro facilities is limited. For this reason, the IRP did not concentrate on these types of resources, but it should not be construed that NPPD is eliminating them from consideration. Any renewable resource will be considered by NPPD if it is determined to be cost effective.

Wind currently appears to provide the best economics for renewable generation in NPPD's service territory today. Various sources have indicated Nebraska is ranked as the 6th highest state in the nation for potential wind resources. However, the variable nature of wind is its greatest liability. Wind generation must lean on other resources when it is not operating, or

operating less than predicted. This increases the overall system costs, and is referenced by the term, wind integration costs. Since there is generally an inverse correlation between wind and load, most of the wind generation can not be counted on to meet NPPD's peak load. Finally, the best wind locations are typically away from load centers, meaning additional transmission capability is required, which has the ability to make many wind generation projects uneconomical.

Cogeneration

Cogeneration is the use of fuel to generate two different types of energy for end use; steam and electricity. Cogeneration can be used by industrial processes that require steam. The benefit of a cogeneration facility is the efficiency of the electrical generation. The incremental efficiency of the electrical generation can be on the magnitude of 60-70%, which is roughly twice as efficient as some of NPPD's steam units in operation today. The downside of cogeneration is that NPPD can not reliably plan for these additions, since it is up to the industrial user to choose if they add cogeneration to their process. The IRP evaluates cogeneration facilities using coal, natural gas, or biomass as potential fuel types.

Peaking

Peaking capacity is typically defined by relatively low capital costs and high operating costs versus other types of units. The capacity factor for peaking resources is commonly between 1% and 10%. Peaking resources are normally used for serving the incremental load during peak time periods, operating reserves, and planning reserves. The IRP evaluated natural gas fired combustion turbines as potential peaking resources.

Intermediate

Intermediate capacity is typically defined by its costs falling between peaking and baseload units. Capacity factors between 15-50% are common for intermediate resources. The IRP evaluated natural gas fired combined cycle units and hydro pumped storage units as potential intermediate resources.

Baseload

Baseload capacity is typically defined by its relatively higher capital costs and low operating costs versus other types of units. Capacity factors greater than 60% are common for baseload units. The IRP evaluated pulverized coal, coal gasification (i.e., IGCC), and nuclear units, including increasing the capability of NPPD's existing Cooper Nuclear facility, as potential baseload resources.

IRP Model

NPPD developed a robust spreadsheet model based on previous work completed with outside consultants that included the capability of modeling uncertainties and scenarios of interest for the IRP. The model was designed such that it would be capable of:

- Modeling uncertainties of a number of variables, including fuel, market prices, load growth, capital, and operating costs.
- Modeling different carbon and renewable portfolio scenarios.
- Modeling numerous types of new units and resource plans.
- Providing a reasonable estimate of generation from new and existing resources.
- Analyzing the different resources plans under the different scenarios and uncertainty distributions using Monte Carlo simulation.
- Providing a range of NPV values based on the scenarios, resource plans, and variables outlined in the model, along with the annual revenue requirement for each year in the study period.

Two regulatory uncertainties were determined to have a major impact on the future; 1) carbon regulation, and 2) renewable portfolio standards. Although presently there are no carbon regulations or RPS laws that NPPD must meet, it is probable that some type of regulation may be required to be met in the future.

Twelve[2] resource plans were designed to meet one of three different planning scenarios; 1) Minimal Regulation (low CO_2 and low RPS assumptions), 2) Moderate Regulation (base CO_2 and base RPS assumptions), and 3) Extreme Regulation (high CO_2 and high RPS assumptions). The IRP model ran 5,000 Monte Carlo simulations for each of the twelve expansion plans. The net present value (NPV) of wholesale revenue requirements was calculated for each simulation. The results for each plan are presented as a distribution of likely outcomes between the 10th and 90th percentile value. A risk measure was also calculated for each plan to represent the relative risk of extreme outcomes (greater than the 90th percentile) associated with the plans. Additional analysis was completed to determine the sensitivity of the expansion plans to changing the uncertainty variables.

Results

The four lowest cost resource plans based on the expected value (mean, or average) of the NPV costs of wholesale revenue requirements over the study period (2008 – 2027) using the probability regulation scenario are: (Reference **Exhibit 9.1-2** for a description of these expansion plans.)

- Mod1 Resource Plan - $12.90 billion
- Mod3 Resource Plan - $12.94 billion
- Min4 Resource Plan - $12.97 billion
- Min1 Resource Plan - $13.05 billion

[2] Initially twelve representative resource plans were developed for detailed analysis in the IRP model. As a result of comments received through the public input process regarding the draft 2008 IRP report, NPPD developed four additional resource plans to further study alternative Energy Efficiency program assumptions around the Mod 1 plan. The results from these additional plans are discussed in section 9.6. A detailed description of each plan, including the additional four, can be found in Appendix D.

The table below summarizes the top resource plans for each of the three possible regulatory scenarios (e.g. minimum, moderate, and extreme):

- Minimum Environmental Regulation - $12.05 billion Min4 Resource Plan
- Moderate Environmental Regulation - $12.59 billion Mod1 Resource Plan
- Extreme Environmental Regulation - $14.38 billion Ext4 Resource Plan

Resource Additions by 2027

(in MW unless otherwise indicated)

	Regulation Scenario		
	Minimum	Moderate	Extreme
Resource Plan (1)	Min4	Mod1	Ext4
Energy Efficiency	69	161	383
Wind	415	665	1,365
Solar			100
Biomass (2)			75
Cogeneration	60	160	150
Combustion Turbine	150		
Combined Cycle		237	
CNS Uprates	60	60	60
NC #2	157	157	157
New Coal (net) (2)	443	143	143
Overall Expected NPV (M$) (3)	12,973	12,900	13,728
Expected NPV (M$) (4) (5)	12,052	12,586	14,384
2027 Surplus Capacity	16	13	221

(1) The resource plan listed for each regulation scenario is the lowest cost plan that was specifically designed for that regulation scenario. Lowest cost is based on the probability weighted value for all simulations for all scenarios. This does not necessarily mean that the plans shown are the lowest cost plans for each scenario. Refer to section 9.4 for further details.
(2) Mod1 included a coal unit with 5% biomass, or ~ 15 MW. This line also includes any unit reductions. The new coal unit in the Ext4 plan includes carbon capture.
(3) NPV is the overall probability weighted expected value for all regulation scenarios. The probability weighting is 25% minimum regulation, 50% moderate regulation, 25% extreme regulation.
(4) NPV is the expected value of that resource plan for given regulatory scenario (e.g. 100% certainty of a minimum, moderate, or extreme scenario happening).
(5) Mod1 is the lowest cost plan in the 100% extreme regulatory scenario. The expected value for Mod1 in this case is $14,277 M.

As expected, the minimal resource plans tend to perform better under the low CO_2 cost scenario, and the moderate resource plans perform better under the base CO_2 cost scenario. What wasn't expected is that the moderate and minimal resource plans generally performed better than the extreme resource plans under the high CO_2 cost scenario. One potential reason may be due to the fact the IRP model allowed NPPD to purchase an unlimited amount of CO_2 allowances if its emissions exceeded the amount of free allowances. Thus, the risk of not being able to purchase CO_2 allowances was not included in the model. This uncertainty is designated for further study in the Action Plan.
The top four uncertainty variables for each of the lowest cost resource plans are: 1) CO_2 cost, 2) load forecast, 3) coal fuel cost, and 4) non-firm market price. These four variables explain approximately 90% of the variation in NPV values. CO_2 cost alone explains approximately 50% of the variance. The RPS requirement variable ranks between 5th and 7th largest significance in each of the top performing plans, and is therefore not as influential on costs as the other top variables.

Mod1 and Mod3 resource plans tend to put NPPD in a better economic position than Min1 and Min4 when looking beyond the IRP study period. The average annual costs for the Mod1 and Mod3 plans are nearly identical for the last 3 years of the study period (i.e. 2025 – 2027). However, the average annual costs for Min1 and Min4 are 3.5% and 1.7% higher respectively over the same time period.

There is greater variation when it comes to CO_2 emissions when looking at the last 3 years of the study period. Min1 CO_2 emissions are 15% higher, Min4 is 17% higher, and Mod3 is 6% higher than Mod1 CO_2 emissions. The absolute amount of CO_2 emissions continues to grow with the Mod1 and Mod3 plans though at a lower rate than overall load growth. It would take implementation of one of the extreme plans (Ext4 was studied) to have less CO_2 emissions at the end of the study period than in 2005. None of the plans studied would satisfy a 1990 based CO_2 emissions cap.

In the short term (through 2014), the four lowest cost plans are very similar to one another. The only differences are in energy efficiency and cogeneration assumptions. The major change occurs in the 2017-2022 time period, when the next major resources are installed.

Some runs were also made for a No CO_2 cost / No RPS scenario for informational purposes although that scenario was not weighted in with the other scenarios for weighted or overall expected value results. Reference Section 9.4 for more details.

For purposes of comparisons in future IRPs and achievement of measurement goals, the Mod1 plan will be used for the base case. For action items that relate to measurable goals, 2008 shall be the base reference year.

Action Plan

The action plan is designed to implement common themes from the best performing resource expansion plans that meet the IRP Planning Principles and better position NPPD for the future. It is expected that the IRP will be updated on a regular basis as business conditions and available

technologies change. Therefore, the action plan will also be periodically reviewed and updated to align with the changing business environment.

- Implement energy efficiency programs that can be utilized by NPPD's customers to improve conservation and utilization of electricity provided by NPPD. At least 41,100 MWh should be met through energy efficiency and conservation programs by 2014. This energy equates to 14% of NPPD's annual energy load growth or 0.25% of total native load.
- Complete negotiation of a Power Purchase Agreement for up to 30 MW more of wind energy for delivery to NPPD starting in 2008 or 2009. Note: By the end of April 2008 the District has contracted for approximately 120 MW of the original 150 MW of wind energy additions authorized by the Board in October 2007 to be delivered starting in 2008 or 2009. The total renewable energy addition is to be approximately 551,000 MWh per year.
- Construct or purchase an additional 100 MW to 150 MW (approx. 367,000 MWh/yr to 551,000 MWh/yr) of wind energy for delivery to NPPD starting in the 2014 to 2016 timeframe.
- Complete a study of the operational impacts of adding significant amounts of variable renewable energy resources to NPPD's system.
- Complete a study of transmission system expansions needed to support significant amounts of new wind generation in the state.
- Study the economic and operational benefits of installing new peaking generation to provide a hedge against aging combustion turbine fleet issues, lack of cogeneration development, and wind integration impacts.
- Study the economic and operational benefits of adding a hydro pumped storage facility to NPPD's resource mix to hedge against wind integration impacts and to improve the operational flexibility of the system.
- Complete a strategic asset plan for NPPD's existing coal fired units.
- Seek opportunities to partner with industry organizations or other utilities to evaluate carbon neutral generation technologies.
- Complete project planning and develop a business case for completing a power uprate at CNS in the 2012 to 2014 timeframe.
- Promote and support the development of cogeneration and distributed generation resources that provide economic and environmental benefit to NPPD and its customers. A goal of 100 MW of cogeneration should be added to NPPD's system by 2014.
- Work with NPPD's customers to develop and implement projects that use agricultural based methane or other waste products to generate electricity and create other environmental benefits (e.g. carbon offsets).
- Examine further the risk associated with the dependence on the availability and price of CO_2 allowances and offsets for compliance with potential greenhouse gas regulations.
- Engage in energy related research at the state (Nebraska Center for Energy Sciences Research at the University of Nebraska – Lincoln) and national level (Electric Power Research Institute)

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Native Load Growth Team, Climate Change / Greenhouse Gas Regulation Team,
Renewable Resource Strategy Team,
Energy Efficiency & DSM Strategy Team, and
Cogeneration Strategy Team.

LIST OF ABBREVIATIONS

AWEF – Ainsworth Wind Energy Facility
BPS – Beatrice Power Station
CAIR – Clean Air Interstate Rule
C-BED – Community Based Energy Development
CFR – Code of Federal Regulations (Ex: 10CFR50 is Title 10 of the Code of Federal Regulations Chapter 50)
CNPPID – Central Nebraska Public Power and Irrigation District
CNS – Cooper Nuclear Station
CO_2 – Carbon Dioxide
CREB - Clean Renewable Energy Bond
CT – Combustion Turbine
DSM - Demand Side Management
EIA - Energy Information Administration
EPRI – Electric Power Research Institute
GED – Global Energy Decisions
GFPS – General Firm Power Service
GGS – Gerald Gentleman Station
GHG – Greenhouse Gases
Hg - Mercury
HVAC – Heating, Ventilation and Air Conditioning
IGCC – Integrated Gasification Combined Cycle
IRP – Integrated Resource Plan
LOLE – Loss of Load Expectation
MAPP – Mid-Continent Area Power Pool
MEAN – Municipal Energy Agency of Nebraska
MPC – Multi-Pollutant Control
MRO - Midwest Reliability Organization
NC2 - Nebraska City Unit # 2
NCESR – Nebraska Center for Energy Sciences Research
NO_x – Nitrogen Oxide
NPCC - Northwest Power and Conservation Council
NPPD – Nebraska Public Power District
NPV – Net Present Value
NRC – U.S. Nuclear Regulatory Commission
O&M – Operations and Maintenance
OPPD – Omaha Public Power District
PTC – Production Tax Credit
PPA – Power Purchase Agreement
PS – Pumped Storage Hydroelectric Generation Facility
PV – Photovoltaics
REC – Renewable Energy Credits
REPI – Renewable Energy Production Incentive
RFP – Request for Proposal

RMI – Rocky Mountain Institute
RPS – Renewable Portfolio Standard
SCPC – Supercritical Pulverized Coal
SO_2 – Sulfur Dioxide
TAG – Technical Assessment Guide
TRC - Total Resource Cost test
WAPA – Western Area Power Administration

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1. INTRODUCTION AND OVERVIEW

Nebraska Public Power District (NPPD) is Nebraska's largest electric generating utility, with a chartered territory including all or parts of 91 of the state's 93 counties. It was formed on Jan. 1, 1970, through the merger of the former Consumers Public Power District, Platte Valley Public Power and Irrigation District, and the Nebraska Public Power System. A public corporation and political subdivision of the state, NPPD is governed by an 11-member Board of Directors, popularly-elected from NPPD's chartered territory.

NPPD serves the total wholesale power requirements of 52 municipalities and 24 public power districts and cooperatives. NPPD also serves 80 municipalities at retail totaling nearly 88,000 customers. NPPD's electrical grid system consists of 4,300 miles of high voltage transmission lines (115 kV and higher) and 796 miles of subtransmission lines for a total of 5,096 miles.

NPPD uses a mix of generating facilities, including nuclear, coal, oil, and natural gas, fueled resources. NPPD also generates electricity from renewable resources utilizing wind and hydro-power (water). NPPD purchases electricity from the Western Area Power Administration, which is a marketing and transmission agency for Federal hydropower.

This report meets NPPD's Integrated Resource Plan (IRP) cooperative filing requirement per Western Area Power Administration's (WAPA) formal filing obligation of a five-year complete IRP report for 2008. A complete list of entities covered under the NPPD IRP is provided in Appendix A. This IRP is being prepared on behalf of:

> Nebraska Public Power District (NPPD), NPPD's Wholesale Requirements Customers receiving WAPA power benefits through NPPD's purchases from WAPA, and the following direct purchasers of WAPA power (those receiving their own allocation):
>
> > Auburn, Beatrice, Beatrice State Development Center, Belleville, KS, Cambridge, David City, Deshler, DeWitt, Emerson, Franklin, Indianola, Laurel, Lodgepole, Lyons, Madison, Mullen, Neligh, Norfolk Veterans Home, Ogalala Sioux Tribe, Omaha Tribe, Ord, Plainview, Randolph, Santee Sioux Tribe, Schuyler, South Sioux City, Spalding, Wahoo, Wakefield, Wauneta, Wayne, Wayne State College, Wilber, Winnebago Tribe, Winside, and Wisner

1.1 Disclaimer

Assumptions contained herein regarding potential CO_2 requirements, RPS requirements and other assumptions about future public policy provisions are for planning purposes only and are intended to provide credible planning scenarios, but are neither an endorsement of any particular regulatory regime or an attempt to predict the specific requirements of any regulatory regime that may be established. Costs for various alternatives are based on numerous assumptions and could increase or decrease under more detailed analysis involving specific projects. The assumptions and modeling scenarios and results described are hypothetical.

1.2 Why Complete an IRP?

Integrated resource planning includes the combined development of electricity supply options and demand side management options (efficiency, conservation, and demand response) resulting in a least cost plan for providing energy services to NPPD's customers over the study period (2008 – 2027). This least cost approach to resource planning includes consideration for some environmental costs and assesses risk associated with the various planning options. Integrated resource planning is an ongoing process that must be flexible enough to respond to changes in the business environment.

NPPD's goal with this IRP is to assure an adequate and reliable long-term electric supply for our customers at a reasonable cost. The IRP provides an analytical framework for assessing supply side and demand side resource options to support informed decision-making by NPPD's Board of Directors for future resource investment. The IRP also serves as a communication vehicle to engage our stakeholders in the resource planning process by educating them further on the risks facing our industry, while allowing them to participate in the planning process and influence its outcome. The IRP must reach a balanced position after considering various priorities and accounting for diverse and sometimes conflicting stakeholder views. Ultimately it is NPPD's responsibility to determine the best action plan to meet customer and other stakeholder needs.

This IRP for NPPD is developed against a back drop of future market and regulatory uncertainty facing the electric utility industry. The IRP report identifies and evaluates several major cost and risk factors, including native load growth, increasing cost and volatility of non-firm electricity and fuel markets, environmental regulation of carbon dioxide (CO_2) and other greenhouse gases, and creation of renewable portfolio standards. Potential resource expansion plans are evaluated under a range of future scenarios, and the IRP provides comparative results based on cost and risk.

The IRP provides insight as to the most favorable approach for adding resources to meet future native load requirements while minimizing cost and risk. The IRP does not provide an exact expansion plan to be followed for the next 20 years. Nor does it evaluate every possible combination of resources to meet future native load requirements. The IRP is intended to provide a "directionally correct" vision of the future for decision making. While the modeling employed is intended to be accurate and comprehensive, it is also intended to support and not replace the judgment of NPPD's decision makers.

1.3 IRP Planning Principles

The IRP must align with NPPD's Vision, Mission, and Strategic Plan. Key objectives from NPPD's Strategic Plan that serve as guiding principles for the IRP process include:

- NPPD will have a diverse power resource mix, consisting of owned facilities and contract purchases, sufficient to meet loads under extreme weather conditions.

- NPPD will evaluate all forms of renewable resources feasible in Nebraska and incorporate them in the total mix of NPPD-owned generation and contract purchases, with a goal of achieving 10% of our energy supply for NPPD's native load from renewable resources by 2020.
- NPPD will strive to increase energy efficiency, support effective economic development that enhances NPPD's load profile, and provide services that are in alignment with NPPD's core business to broaden NPPD's revenue base and reduce overall overhead costs to our customers.

Some general guidelines that were used to help focus the IRP analysis process are:

- Resource expansion plans evaluated and selected in the IRP must meet future native load requirements.

- Resource expansion plans evaluated and selected in the IRP should minimize cost on a long-term basis after considering the effects of various risk factors.

- The IRP should avoid risks associated with investing in resources that do not perform well under a range of future planning scenarios.

- The IRP should focus additional attention to resources that function well under a range of future planning scenarios.

- The IRP should address near term resource needs and position NPPD for the future.

1.4 Regulatory and Contractual Requirements

This IRP meets the following regulatory and contractual requirements.

1.4.1 State of Nebraska (Nebraska Revised Statute 66-1060)

Nebraska Revised Statute 66-1060 states that, "public utilities in Nebraska shall practice integrated resource planning and include least cost options when evaluating alternatives for providing energy supply and managing energy demand in Nebraska". The statute defines least cost as, "providing reliable electric services to electric customers which will to the extent practicable, minimize life-cycle system costs, including adverse environmental effects, of providing the services". The statute also includes the following expectations:

- Evaluation of the full range of alternatives including new generation, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling, and renewable resources
- Account for features of system operation such as diversity, reliability, and dispatchability and other risk factors
- Account for the ability to verify energy savings achieved through energy conservation and efficiency and the durability of such savings over time

- To the extent practicable, energy efficiency and renewable resources may be given priority

1.4.2 Western Area Power Administration

The Energy Policy Act of 1992 requires all of WAPA's customers to submit an IRP to WAPA every five years (10 CFR 905). This requirement is also included in WAPA's long-term power supply contract with NPPD. Integrated Resource Plans submitted to WAPA must meet the following criteria:

- Conduct load forecasting for the study period
- Identify and compare all practicable energy efficiency and energy supply resource options
- Describe efforts to minimize adverse environmental effects of new resource acquisition
- Provide opportunity for full public participation
- Include an action plan with timing
- Describe measurement strategies for options identified in the IRP

1.4.3 NPPD Wholesale Power Contract

The current wholesale power contract with NPPD's total requirements customers states that NPPD will be responsible for maintaining a current power resource plan which shows how NPPD's portfolio of power resources will meet the combined requirements of the customers for a period of ten years into the future.

1.5 Interface with the Public

NPPD used a multi-faceted approach to communicate with our customers and other stakeholders. This approach was designed to provide for multiple opportunities to educate our customer base and obtain feedback on the IRP process and the various options being considered. The process included meetings with the NPPD Board of Directors, meetings with customer groups, meetings with interested third parties, and dedicating a portion of NPPD's corporate public website to IRP communication (http://www.nppd.com/irp/). Comments received throughout the public input process have been addressed and incorporated into the IRP as appropriate.

1.5.1 NPPD Board of Directors

NPPD is by definition, as a public power district, an organization that must follow a public process for conducting business, which includes development of the IRP. NPPD's Board of Directors is popularly elected from NPPD's chartered territory. All Board meetings are open to the public, and all meetings are advertised in local newspapers in accordance with Nebraska public meetings laws. The Board normally conducts its meetings in Columbus, NE at NPPD's corporate offices.

The Board held planning retreats in September 2006 and May 2007 to discuss the IRP process, major planning assumptions, supply and demand side resource options, and provide guidance to NPPD staff concerning the development of the IRP. The September 2006 retreat was held in Nebraska City, NE and the May 2007 retreat was held in North Platte, NE.

Regular IRP updates were also provided to the Board during monthly Board meetings, including a session focused on reviewing and receiving comments on the results of the IRP process on January 9, 2008. The Board was asked to consider and approve the IRP during their regular meeting on May 8–9, 2008.

1.5.2 Customer Groups

NPPD has established a Power Resource Advisory Board (PRAB) made up of customer representatives to act in an advisory capacity to NPPD in evaluating power resource issues. The PRAB is made up of representatives of NPPD's firm total requirements wholesale utility customers (e.g. rural power districts, cooperatives, and municipal utilities) and representatives of municipal communities served at retail by NPPD. The representation on the PRAB is selected by the customers, and PRAB meetings are also open to representatives of all customers. One of the roles for the PRAB is to provide feedback to NPPD staff concerning the IRP process, major planning assumptions, supply and demand side resource options.

NPPD conducted an IRP planning retreat with the PRAB in January 2007. The focus of the retreat was to acquaint the customers with the IRP process and major planning assumptions. Regular updates were provided in 2007 (April, July, October, and November) to discuss IRP issues in more detail with the PRAB. A special wholesale and retail customer meeting was held on January 25, 2008 in which all wholesale and retail utility customers were invited to participate and provide feedback on the IRP. NPPD staff has also met with customers on an as requested basis to discuss and obtain feedback on the IRP. The Nebraska Electric Generation and Transmission Cooperative, Inc. also conducted an independent review of the draft IRP (see Appendix G).

1.5.3 Public Meetings

A series of public meetings were held in February and March 2008 at Kearney, Lincoln, Norfolk, Scottsbluff, and North Platte to allow for additional public discussion of the IRP and provide for an opportunity to obtain additional feedback. The public meetings were advertised in local newspapers, and invitations were sent to wholesale and retail utility customers. Comments and responses were published on NPPD's corporate website and are included as Appendix G to this report.

1.5.4 NPPD Corporate Website (http://www.nppd.com/irp/)

In November 2007 NPPD added information specific to NPPD's IRP process to its corporate website. This included information about the IRP process, contact information, and the 2003 IRP submitted by NPPD to WAPA. The website also provides an online form to ask questions

or provide comments concerning the 2008 IRP (see Appendix G). A draft of the 2008 IRP was published to the website in January 2008 and the final version was published after Board approval in May 2008.

2. EXISTING SYSTEM & COMMITTED RESOURCES

2.1 Existing

NPPD uses a diverse mix of generation resources such as coal, nuclear, natural gas, hydro, and wind to meet the needs of its customers. Appendix B lists all of NPPD's existing generation resources, including in-state hydro purchases and peaking capacity purchases. Exhibit 2.1-1 shows the energy source split used to serve NPPD's customers in 2007, where Exhibit 2.1-2 presents the capacity breakdown.

Exhibit 2.1-1 – Sources of Energy to Meet Service Obligation

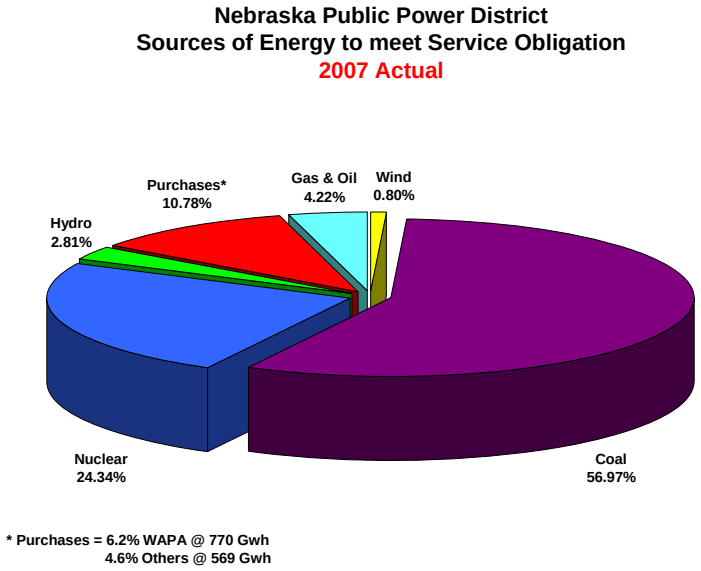
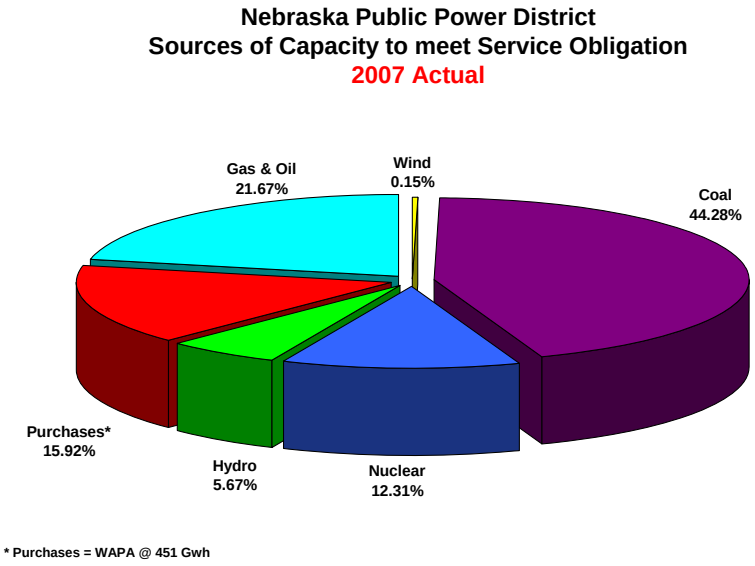


Exhibit 2.1-2 – Sources of Capacity to Meet Service Obligation



In 2007 59 percent of NPPD's native load energy obligation was met with coal generation. Gerald Gentleman Station (GGS), a coal plant located near Sutherland, is Nebraska's largest generating plant. GGS consists of two generating units which have the capability of generating 1,365 MW of power. GGS Unit 1 which has been in-service since May, 1979 has a net generation capability of 665 MW. GGS Unit 2, the larger unit at 700 MW net, has been commercial since January, 1982. Gentleman Station is fueled using sub-bituminous low sulfur coal from Wyoming's Powder River Basin. Participation sales with other utilities amount to nearly 250 MW of Gentleman Stations' output in 2007.

Sheldon Station, a coal fired plant near Hallam, consists of two boilers that can generate 225 MW of electricity. Sheldon Unit 1, a 105 MW unit, was commissioned in 1961 while Unit 2, a 120 MW unit, was added in 1968. Participation contracts account for 67.5 MW of 225 MW total. Sheldon Station also burns Powder River Basin low-sulfur coal.

NPPD's second largest source of generation, and largest single generation unit, is Cooper Nuclear Station (CNS). CNS was put into operation in July, 1974. NPPD owns and operates CNS but has support services contracts with Entergy Nuclear Nebraska through 2014. In 2007, CNS accounted for approximately 24 percent of NPPD's service obligation. CNS, which has a net capacity of approximately 760 MW, is a Boiling Water Reactor (BWR) unit. In 2007, participation contracts account for 430 MW of the capacity. On January 1, 2010 NPPD will reclaim 250 MW, while all other participation contracts end by early 2014. NPPD's operating license for CNS expires in early 2014 but NPPD is currently in the process of filing a 20 year operating license extension with the Nuclear Regulatory Commission (NRC).

Beatrice Power Station (BPS), a combined cycle gas fired unit, came on-line in January, 2005. BPS uses two combustion turbines and one steam unit to generate up to 237 MW. Canaday Station is an approximate 118 MW gas fired unit. Canaday, constructed in 1958, was originally

owned by Central Nebraska Public Power & Irrigation District. In 1995 NPPD acquired the "mothballed" plant and had it accredited in June, 1998. Canaday can also burn No. 6 fuel oil.

NPPD also owns three gas turbine peaking units. The Hallam unit can generate 52 MW and can run on natural gas or distillate oil. The Hebron and McCook units are both 51 MW and run on distillate oil.

NPPD owns and operates three hydroelectric generation facilities. The largest is a two unit hydro located near North Platte. The North Platte hydro consists of two 12 MW units for a total of 24 MW capacity. This hydro, operating since 1937, uses water from the North and South Platte rivers. After flowing through the hydro, the water reenters the South Platte River and powers other hydros and irrigation needs downstream. The Kearney Hydro, the oldest in the state, has been operational since 1921. This hydro was rehabilitated in 1997 and generates about 1 MW. The Spencer Hydro, situated on the Niobrara River in northern Nebraska generates about 1.8 MW from two turbines. Spencer has been operating since 1927.

In addition to NPPD owned hydro facilities, NPPD also purchases the output of hydro generation owned by Loup Power District and Central Nebraska Public Power & Irrigation District (CNPPID). Loup owns and operates two facilities along the Loup canal system which in 2007 had a generation capacity of approximately 42 MW. Loup has recently completed refurbishment of the hydros resulting in a slightly higher generation output of approximately 47 MW total. CNPPID owns and operates four hydro electric plants. Kingsley Hydro, CNPPID's largest facility at 38 MW, is directly below Kingsley dam on Lake McConaughy. Three other hydros, (Jeffrey, Johnson No. 1 and Johnson No. 2) are located on a supply canal below the confluence of the North Platte and South Platte Rivers and can supply another 54 MW.

The Ainsworth Wind Energy Facility (AWEF), the state's largest wind facility, was built by NPPD in 2005. The facility consists of thirty six 1.65 MW turbines for a total nameplate capacity of approximately 60 MW. OPPD, MEAN and the City of Grand Island participate in 30% of AWEF's generation. JEA, a public power utility in Jacksonville, Florida, purchases 10 MW of environmental benefits of AWEF, while NPPD retains JEA's share of energy and capacity.

Several of NPPD's wholesale municipal customers own internal combustion generators. NPPD has capacity purchase agreements with these municipals for an additional 103 MW generation capacity. These smaller units are generally dispatched only at peak usage times, as emergency generation or to stabilize local transmission constraints.

In addition to the above generation facilities, NPPD purchases approximately 451 MW of firm power from the Western Area Power Administration (WAPA) and other capacity or energy on both a short-term and non-firm basis in the wholesale energy market. WAPA purchases make up over half of NPPD's total energy purchases. Of the capacity purchases, 288 MW are a WAPA peaking product available in summer months.

2.2 Committed

Committed resources are future resources that have been approved by NPPD's Board of Directors to proceed.

2.2.1 Neb City 2

Nebraska City Unit 2 is an approximate 660 MW coal-fired generating unit that OPPD is constructing adjacent to its Nebraska City Unit 1 plant. In October 2003, NPPD's Board of Directors approved a life of plant power agreement with OPPD to receive 23.67%, or approximately 157 MW, of Neb City 2's output. Commercial production of electricity is expected to commence by May, 2009.

2.2.2 Cogeneration

A large ethanol plant in NPPD's service territory has announced that they would build a coal-fired cogeneration (cogen) plant at their facility. The cogen plant will be permitted to burn a blend of fuels, including high and low sulfur coals, tire derived fuel and biomass to produce process steam and electricity. Cogeneration reduces the amount of fuel burned per unit of energy output, and reduces the corresponding emissions of pollutants and greenhouse gases. Intentions are for 30 MW of cogen to be operational in 2009 and an additional 30 MW in 2010. At this time the contractual arrangement with this facility has not been finalized.

2.2.3 Wind Purchase Power Agreements (report on the agreements or what is expected)

In July of 2007, NPPD sent out a RFP to bidders for wind-powered generation capacity, associated energy, and renewable attributes to be located near NPPD's transmission system. Private wind development is being pursued due to the availability of the Production Tax Credits that are not available to public utilities.

In August, 2007 NPPD received 10 proposals from 7 developers, including 2 Community-Based Energy Development (C-BED) proposals. In October, NPPD's Board reviewed the proposals and authorized management to negotiate with three of the developers, including both C-BED projects, for a total of up to 150 MW of generation capacity. NPPD has invited other Nebraska utilities to participate in these agreements.

In March, 2008, NPPD executed an agreement for a 20-year power purchase agreement for nearly 80 MW from the Elkhorn Ridge Wind Project to be constructed near Bloomfield and operational by the end of 2008.

In April 2008, NPPD executed an agreement for a 20-year power purchase agreement for approximately 40 MW from the Community Wind Energy Transmission, LLC to be constructed near Bloomfield and operational by the end of 2009.

2.2.4 CNS Appendix K

In August 2006, NPPD's Board of Directors approved a project to implement the Appendix K power uprate at CNS. The NRC originally licensed CNS for 2 percent less reactor power output than the design would allow to provide for uncertainty in the ability to determine actual reactor thermal power, due mostly to the inability to accurately measure feed water flow. Technology today is able to measure feed water flow at less than 0.3 percent accuracy. The NRC recognized

the new technology in 1999 and revised 10CFR50, Appendix K. This project, which will be installed during refueling outage 24 (RE-24) in the spring of 2008, will allow CNS to operate at approximately 12 MW higher.

2.3 Summary of Existing & Committed Resources

NPPD has a diverse mix of generation resources to provide reliable electric service to its customers in the near future. In addition to their existing capacity, NPPD is participating in OPPD's Nebraska City Unit 2 coal plant, is purchasing wind energy from private wind developers and expects 60 MW of cogeneration to come online. NPPD will also recapture 570 MW of capacity by 2014 as participation contracts at CNS and GGS expire. Exhibit 2.3-1 summarizes these capabilities.

Exhibit 2.3-1 – Sufficient Generation Capability 2007-2014

Existing System & Committed Resources

- NPPD will have adequate resources to meet customer needs in the near future

Resource	Amount	Year
CNS Power Uprate	11 MW	2008
Neb. City Unit 2	157 MW	2009
Wind Power Purchase Agreement	60 – 150 MW (nameplate) **[10 – 26 MW accredited]**	2009
Cogeneration	30 MW 30 MW	2009 2010
Generation Recapture	570 MW	2009 - 2014
Total	**808 – 824 MW**	

Projected load and capability graphs with only existing/committed resources are included in Appendix C as **Exhibit C-1** for the summer season and **Exhibit C-2** for the winter season. These graphs generally confirm that NPPD has sufficient resources to meet its seasonal capacity obligations in the near future, although short-term capacity purchases may be required during the next few years to maintain adequate reserve requirements under severe weather conditions during the summer season. Surplus capacity during the winter season is projected to be comfortably higher than the corresponding summer season over the first half of the study. However, by the end of the study period (2027), the requirements for additional resources during the winter season are forecast to be similar to those in the summer season.

3. LOAD FORECAST

NPPD employs both top-down and bottom-up forecasting methods. The top-down, or comprehensive forecast uses service area socioeconomic "drivers" to project loads based on overall service area economic and demographic trends. The comprehensive forecast includes models for NPPD system level demand and energy at the Busbar, or system inlet. The comprehensive forecast also develops customer class energy forecasts at the end-use meter level. The bottom-up or distributor level forecast consists of producing monthly demand and energy forecasts for all of NPPD's wholesale distributors, including NPPD Retail. The distributor level forecast uses data at Bus A, the metering point for wholesale billing. The two methods are reconciled by losses so that Busbar, Bus A, and meter level forecasts are consistent with each other.

3.1 Comprehensive Load Forecast

NPPD normally prepares the comprehensive load forecast every five years; the most recent was completed in November 2002. The comprehensive forecast involves acquiring history and projections with high and low scenarios for socioeconomic variables including; personal income, employment, population, and households for the NPPD service area and state level alternative fuel prices. An electricity price forecast based on NPPD's rate track is developed in-house. NPPD also produces an end-use irrigation forecast. Irrigation is an important and unique part of NPPD's summer peak demand and summer energy consumption. The comprehensive forecast is considered top-down, since models assume the service area economy drives load growth for NPPD demand and energy.

3.1.1 Forecast Uncertainty

To incorporate uncertainty in the comprehensive forecast NPPD uses high and low scenarios for all input variables. The scenarios are meant to represent points on a standard 10, 50, 90 percent cumulative probability distribution. The 10 percent or low scenario indicates the variable will achieve a value above the low scenario 90 percent of the time. The 90 percent or high scenario represents a value which one would expect to be exceeded 10 percent of the time. The 50 percent or baseline scenario represents a value that would be exceeded half the time, and conversely the actual value would be below baseline half the time. Short-term uncertainty is due mainly to weather variation while long term uncertainty primarily depends on service area economic and demographic trends. NPPD can create or acquire scenarios for any input variable in the load forecast. Where adequate historical data exists, NPPD uses software to develop stochastic or Monte Carlo models for selected variables.

3.1.2 Irrigation Forecast

The end-use irrigation forecast makes projections of connected load, irrigation energy, and irrigation contribution to peak demand. Those main results depend on projections of total irrigated acres, the share of total acres served by electricity, the characteristics of irrigation

systems, the amount of water pumped, and the amount of energy required. Also considered is the amount of land and water available for irrigation, including aquifer exhaustion, the profitability of irrigation, the price of electricity and competing fuels, and the availability of electricity and competing fuels.

New irrigation development is modeled with econometric models for 20 multi-county regions in the NPPD service area. Irrigation development depends on interest rates, crop yields, crop prices, available land, well drilling moratoriums and water use policies. Total irrigated acres are estimated by adding new development to existing irrigated acres, and subtracting acres reverting to dryland.

Qualitative choice models provide projections of the electric share of total irrigated acres. NPPD conducts an Irrigation Energy Source Survey of agricultural producers to provide data for modeling fuel choice decisions made by irrigators. The models include data on fuel price, availability of alternative fuels, and well motor power requirements in horsepower. Connected electric irrigation load is then a function of total irrigated acres and electric share.

The majority of uncertainty in irrigation connected load is driven by volatility in fossil fuel prices. NPPD creates baseline, high, and low scenarios for irrigation connected load based on scenarios of electric, diesel, natural gas, and propane prices, as well as interest rates and crop prices.

Additional models provide projections for irrigation contribution to summer peak demand based on coincidence factors and demand-side management (DSM) practices. Irrigation accounts for the largest share of NPPD's demand-side managed loads. NPPD's summer wholesale rate structure provides a significant incentive for wholesale customers to control loads during on-peak hours which are deemed as "non-waived" for billing purposes. NPPD conducts a post-season survey of wholesale customers each year to develop data on customer irrigation and non-irrigation DSM program effects at the time of NPPD's summer peak. In 2007 NPPD wholesale customers controlled off 515 MW of irrigation load at the time of NPPD's "billable" system peak. An additional 57 MW, or so, of non-irrigation load is also controlled off at the time of NPPD's billable peak.

Irrigation energy projections are based on connected load, depth to water, irrigation system type, and well flow rates. Actual irrigation energy depends on rainfall and soil moisture conditions. The irrigation projections then become part of the overall NPPD comprehensive load forecast.

3.1.3 Customer Class Energy Forecast

The comprehensive load forecast develops energy projections by customer class for the entire NPPD system. NPPD's wholesale distributors, including 52 Municipalities, 25 Rural Power Districts, and NPPD Retail provide meter level sales information by customer class, (e.g. residential, commercial, and industrial). Wholesale distributors submit meter-level data on a monthly basis. The data are compiled to represent the entire NPPD system for modeling and forecasting purposes.

Forecasts for residential, commercial, and public authority customers are based on projections of service area households and population. High and low scenarios for population and households provide alternative scenarios for customer counts.

For the residential class, NPPD tracks appliance saturation rates by conducting and compiling a Residential Appliance Saturation Survey. Projections of appliance stocks or saturation rates are estimated using a Gompertz, or S-curve model. NPPD also develops high and low scenarios for appliance stocks.

Energy models rely on projections of customers, appliance stocks, energy prices, and weather conditions. Historical data and projections for customers, appliance stocks, weather (heating and cooling degree-days), electricity prices, and alternative fuel prices, serve as inputs to econometric models of energy by customer class. Energy models for residential, commercial, industrial, public authority, streetlight, seasonal, and irrigation make up total NPPD energy. Estimated losses from Busbar to meter provide an estimate of total system energy at the Busbar level.

3.1.4 Peak Demand Forecasts

Peak demand is forecasted econometrically using inputs similar to the energy models, including personal income, customers, appliance stocks, and peak day weather conditions. In addition, a statistically adjusted engineering specification is included for irrigation peak demand. In this way the DSM impacts of wholesale customer direct load control programs get incorporated into the projection for summer "billable" peak demand. The assumptions made for coincidence factors in the irrigation model discussed above indicate the amount of load management implicit in the forecast for summer peak demand. NPPD expects an increase in the amount of load controlled off at peak. As connected load grows the share of irrigation load enrolled in load management programs increases as well, causing an upward trend in the amount of load available for control.

Weather variables in demand models are more focused on the peak day and temperature build up prior to the peak day. Short-term irrigation demand is also dependent on rainfall and soil moisture conditions.

The main focus with regard to uncertainty modeling for NPPD is summer peak demand. Over the last eight years the average absolute deviation from forecast for summer peak demand was 2.2 percent while the error exceeded three percent three times. Summer peak demand is highly volatile due to large swings in the contribution from irrigation and air conditioning. Annual system energy, on the other hand, is less volatile and somewhat easier to forecast. The average absolute error for system energy during the same eight years was only 1.0 percent. Over the last four years the absolute error in annual energy averaged only 0.22 percent. For resource planning purposes NPPD uses the high weather scenario for summer peak demand which is based on more extreme than usual weather conditions.

3.2 Distributor Level Forecast

The distributor level or bottom-up forecast is completed annually and uses time-series models to project monthly peak demand and energy for each wholesale distributor. As discussed above, in addition to NPPD Retail's eight billing regions, NPPD serves 25 Rural Power Districts and 52 Municipalities at wholesale. The distributor forecast examines a number of model specifications and selects the most appropriate based on the model's ability to project actual loads from a holdout dataset, which is typically the last year of actual data. The method is essentially a modeling competition between various ARIMA (autoregressive integrated moving average) model specifications. A number of other diagnostic statistics such as load factors and growth rates determine final model selection. In all, NPPD develops forecasts for nearly 90 data series each, for demand and energy in the distributor level forecast.

For large rural and municipal wholesale customers, NPPD solicits distributor level feedback. Wholesale customers have the opportunity to evaluate results for their utilities' demand and energy forecasts. Wholesale distributors also provide feedback on new load developments that may not show up in trends based on historical data. The recent boom in ethanol projects in Nebraska creates the potential for rapid growth in NPPD's loads. Ethanol projects will result in short-term load growth well above NPPD's recent trends. When a new ethanol plant or expansion becomes fairly certain, the load is added as a step change or step increase to the wholesale customer or distributor forecast.

Corporate Planning and Risk develops the forecast and presents preliminary results to an internal forecast review team for feedback. The forecast review team includes personnel from Customer Services and Delivery, Finance, Pricing and Rates, Retail, Transmission, and Energy Supply. Proposed forecasts then go to the Executive Planning Council for corporate approval. (See Exhibit 8.3.1-1 and Exhibit 8.3.1-2, which show graphs of the load forecast used in this IRP)

4. ENVIRONMENTAL PLANNING AND COMPLIANCE

This section generally describes the major environmental impacts that result from existing resources and shows how potential regulations can influence the choices for future resources. Environmental factors have increasing influence both from regulatory and cost standpoints.

Because the regulations for some of the major environmental factors are still under discussion, this creates uncertainties for their consideration in the planning process. Also, the full range of technologies is not yet developed for meeting these potential regulations leading to more uncertainty.

It is helpful to remember that this report does not represent a one-time decision on the resources for the next twenty years, but rather, is a step in the planning process.

4.1 General

Scope

The integrated resource planning process is not geared to detailed consideration of each and every environmental issue relating to water, air quality, hazardous waste, wildlife, and other societal concerns. Rather, it makes the assumption that there will be ways to deal with the smaller issues in due course; although, all issues will ultimately need resolution. The focus of this study and report is on certain air emissions from the resources; namely carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg), with particular emphasis on CO_2.

Planning and Compliance Perspectives

Oftentimes, utilities can wait for the regulations to be legislated, even fully defined, and then take the necessary steps to comply with the regulations. However, this approach may not be the most beneficial concerning the four air emissions in focus, especially with regard to CO_2.

Some of the larger resource alternatives represent a capital investment of a billion dollars, or more, so that a planning perspective seeks assurance that such a resource will be useful in the future regulatory environment. That is, there can be a benefit to planning ahead for a potential regulation, rather than discounting it because it is not yet in place. This thought is the essence of much of the work represented in this report and relates to two of NPPD's environmental principles for meeting its commitment to the environment:

- Ensure environmental factors are an integral part of planning, design, construction, and operational decisions.
- Comply with all applicable environmental laws and regulations.

Additional information concerning NPPD's environmental activities can be found at www.nppd.com/our_community/environment .

Specifically, with respect to addressing the challenge of global climate change, NPPD approved on Feb 15, 2008 a statement that it will be developing an initial plan whose central focus will be to take cost-effective actions that reduce NPPD's greenhouse gas emissions, such as:

- Developing and maintaining a comprehensive inventory of our system-wide greenhouse gas emissions.
- Incorporating a "shadow" CO_2 price in our business planning processes in order to recognize the potential cost of increasing or decreasing our GHG emissions under possible future mandatory climate change programs.
- Improving, when feasible, the performance of our existing electric generating units through efficiency upgrades and other measures that reduce or avoid greenhouse gas emissions.
- Investing in end-use energy efficiency and renewable energy resources. Investigating technology opportunities for new generation resources and improvements to existing generation resources that are cost effective and reduce our greenhouse gas emissions.
- Developing the expertise and cultivating opportunities to reduce or offset greenhouse emissions.
- Investing in research to develop new solutions to these technologically challenging issues.

Background References and Terminology

For background information on energy-related emissions data and environmental analyses, the U.S. DOE's Energy Information Administration website at www.eia.doe.gov/environment.html is useful and contains, for example:

- Historical greenhouse gas emission data and energy production/usage by state and for all sectors of the U.S. economy,
- Projections of greenhouse gas emission data and energy production/usage for the U.S. as contained in its Annual Energy Outlook reports,
- "Energy Basics 101" tutorial,
- "Frequently Asked Questions" relating to energy and emissions,
- Extensive "Glossary" of energy terms and definitions as used in EIA documents, and
- "Energy A-Z" that has an index of energy topics of interest that is linked to their reports.

Most of the terminology discussion in this section relates to potential CO_2 regulation, although the other three air emissions are modeled with some detail in the study. The effect of CO_2 regulation is considered to be the largest uncertainty. The following definitions are taken from sources as indicated in the footnotes:

> ***Carbon dioxide (CO_2)***[3] ***:*** A colorless, odorless, non-poisonous gas that is a normal part of Earth's atmosphere. Carbon dioxide is a product of fossil-fuel combustion as well as other processes. It is considered a greenhouse gas as it traps heat (infrared energy) radiated by the Earth into the atmosphere and thereby contributes to the potential for global warming. The global warming potential (GWP) of other greenhouse gases is

[3] **EIA "Emissions of Greenhouse Gases in the United States 2006" at www.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/ggrpt/057306.pdf**

measured in relation to that of carbon dioxide, which by international scientific convention is assigned a value of one (1).

Carbon dioxide equivalent*[3]*: The amount of carbon dioxide by weight emitted into the atmosphere that would produce the same estimated radiative forcing as a given weight of another radiatively active gas. Carbon dioxide equivalents are computed by multiplying the weight of the gas being measured (for example, methane) by its estimated global warming potential (which is 21 for methane). "Carbon equivalent units" are defined as carbon dioxide equivalents multiplied by the carbon content of carbon dioxide (i.e., 12/44).

Climate change*[3]*: A term used to refer to all forms of climatic inconsistency, but especially to significant change from one prevailing climatic condition to another. In some cases, "climate change" has been used synonymously with the term "global warming"; scientists however, tend to use the term in a wider sense inclusive of natural changes in climate, including climatic cooling**.**

Global warming*[3]*: An increase in the near surface temperature of the Earth. Global warming has occurred in the distant past as the result of natural influences, but the term is today most often used to refer to the warming that some scientist predict will occur as a result of increased anthropogenic emissions of greenhouse gases.

Greenhouse gases*[3]*: Those gases, such as water vapor, carbon dioxide, nitrous oxide, methane, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride, that are transparent to solar (short-wave) radiation but opaque to long-wave radiant energy from leaving the Earth's atmosphere. The net effect is a trapping of absorbed radiation and a tendency to warm the planet's surface.

Methane*[3]*: A colorless, flammable, odorless hydrocarbon gas (CH_4) which is the major component of natural gas. It is also an important source of hydrogen in various industrial processes. Methane is a greenhouse gas.

Nitrogen oxides (NO_x)*[3]*: Compounds of nitrogen and oxygen produced by the burning of fossil fuels.

Nitrous oxide (N_2O)*[3]*: A colorless gas, naturally occurring in the atmosphere. Nitrous oxide has a 100-year Global Warming Potential of 310.

Sequestration (of carbon)*[3]*: The fixation of atmospheric carbon dioxide in a carbon sink through biological or physical processes.

Sulfur dioxide (SO_2)*[3]*: A toxic, irritating, colorless gas soluble in water, alcohol, and ether. Used as a chemical intermediate, in paper pulping and ore refining, and as a solvent.

Cap and Trade Program [4]*(for regulating greenhouse gas emissions – adapted from Rule 75 to CO_2 regulation):* A market-based approach to reducing greenhouse gas emissions. For example, EPA caps, or limits, the total annual emissions of CO_2 equivalents. The cap is divided into emission allowances that are allocated to each emitting entity. Some allowances may be retained for auction purposes. Each emission allowance represents an authorization to emit one ton of CO_2 during a given year. To demonstrate compliance, the entity is required to hold a number of allowances greater than or equal to its emissions in the regulated time period. Since the total number of allowances allocated or auctioned off to the emitting entities is less than or equal to the target level (cap) of emissions, the program controls the emissions of the greenhouse gases. The allowances are traded at market-based rates so that an emitter of a ton of CO_2 either needs to:

- hold and use an allowance that was allocated for free from EPA, or
- purchase and use an allowance on the market or at auction, or
- obtain a certified offset credit (like for qualifying tree-plantings that remove CO_2 from the atmosphere) in lieu holding an allowance.

On the other side of the market, a holder of an allowance may avoid the associated emission and sell the allowance in the market for its market price.

Purpose and impact of CO_2 regulation

The general purpose of CO_2 regulation (cap and trade market program or tax-based system) would be to minimize the effects of global warming by retarding the increasing concentration of CO_2 in the atmosphere, primarily by reducing the emissions of CO_2 and other greenhouse gases. From NPPD's standpoint, this primarily translates into regulation concerning CO_2 emissions from its coal and oil/gas power plants. If the CO_2 regulation is to be effective for its intended purpose, then one can expect that the monetary drivers, whether tax- or market-based, will force a change over time of the cost relationships between generating alternatives. From a planning standpoint, it is appropriate to give consideration to how these potential relationships may change.

4.2 Historical Emissions

The U.S. DOE has historically required emitters to report the air emissions that are of interest in this section. The individual reports are then tabulated by the DOE, who then makes reports and analyses based on these data as noted in Section 4.1 under *Background References and Terminology*. These data may also be used to make allocations of allowances under a future cap-and-trade program to regulate greenhouse gas emissions. Exhibit 4.2-1 is a table showing historical generation and associated emissions on a total-plant basis during the last eleven years at NPPD's fossil-fueled stations, namely, Gentleman, Sheldon, Beatrice, Canaday, Hebron , McCook, Hallam, and the various capacity purchase units.

[4] **EPA - Clear Air Markets Division "Plain English Guide to the Part 75 Rule" at www.epa.gov/airmarkets/emissions/docs/plain_english_guide_part75_rule.pdf**

Exhibit 4.2-1 – NPPD's Fossil Generation and Emissions on a Total-Plant Basis
(tons are short tons)

Year	Generation (GWh)	SO_2 (tons)	NO_x (tons)	CO_2 (tons)
1997	10,196	25,976	27,189	11,764,620
1998	10,130	26,196	25,092	11,611,912
1999	9,474	24,431	23,905	11,171,164
2000	9,366	26,882	23,713	11,096,432
2001	10,853	36,720	29,036	13,223,970
2002	11,104	37,785	29,578	13,422,270
2003	11,216	35,587	30,000	13,512,052
2004	10,759	36,819	29,208	13,006,207
2005	11,361	33,133	31,533	13,565,708
2006	11,244	35,554	26,071	13,270,417
2007	10,959	33,537	22,213	12,897,607

4.3 Existing Regulations

The operation of NPPD's generation facilities is regulated by several environmental authorities at the local, state, and federal levels. Some of the major regulations that have impact on integrated resource planning as part of the 1990 Clean Air Act Amendments are:

- Acid Rain Program
- New Source Performance Standards
- New Source Review/Prevention of Significant Deterioration
- Clean Air Mercury Rule (CAMR) – March 2005
- Final Amendments to Regional Haze Rule (RHR) – June 2005
- National Ambient Air Quality Standards - Final Revision for Particulate Matter - October 2006; Proposed Revision for Ozone - July 2007

The generation expansion plans studied in this integrated resource planning process are expected to comply with the requirements of these and other known environmental regulations. There are no current regulations applicable to NPPD with respect to its emission of carbon dioxide.

4.4 Potential Environmental Regulation

As noted in the *Planning and Compliance Perspectives* subsection of Section 4.1, the integrated planning process considers potential environmental regulations as well as known regulations. The key potential environmental regulation of concern is the regulation of greenhouse gas emissions, particularly of carbon dioxide.

Ever since the adoption of the Kyoto Protocol of 1997, the U.S. has been debating its regulatory response to climate change issues, being particularly concerned about effects on the economy

and the need to include developing countries in the global response. For examples, two key proposals at the present time are the **Lieberman-Warner "Climate Security Act of 2007" and the Bingaman-Specter "Low Carbon Economy Act of 2007"** (S.1766), both of which would rely on cap-and-trade programs to regulate greenhouse gas emissions.

The **Kyoto Protoco**l is an amendment to the United Nations Framework Convention on Climate Change, adopted by 174 countries and other governmental entities (as of November 2007), according to www.en.wikipedia.org/wiki/Kyoto_Protocol . Of these, 36 developed countries (plus the EU as a party in its own right) are required to reduce greenhouse gas emissions to the levels specified for each of them in the treaty. One hundred and thirty-seven (137) developing countries have ratified the protocol, including Brazil, China and India, but have no obligation beyond monitoring and reporting emissions. The force of the Protocol generally went into effect in 2005, with the countries having mixed success to date of accomplishing their reductions.

It is noteworthy that several states, regions, industries, and businesses have set out varying regulations, pacts, or commitment goals to address the emission of greenhouse gases. For example:

- **The Regional Greenhouse Gas Initiative (RGGI)** is an initiative of ten Northeast and Mid-Atlantic States with detailed information available at www.rggi.org. To address the climate change issue, the RGGI participating states will be developing a regional strategy for controlling emissions. Central to this initiative is the implementation of a multi-state cap-and-trade program with a market-based emissions trading system. The proposed program will require electric power generators in participating states to reduce carbon dioxide emissions.

- **California adopted a Climate Action Team & Climate Action Initiative,** Executive Order # S-3-05 on June 1, 2005 that established greenhouse gas targets that are more aggressive than the federal proposals at this time. A June 30, 2007 report "Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California" was prepared for the California Air Resources Board by the Market Advisory Committee, available at www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF.

- In the Midwest, a **"Midwestern Greenhouse Gas Accord 2007"** was signed by the Manitoba Premier and the governors of nine states, not including Nebraska, resolving to establish a Midwestern Greenhouse Gas Reduction Program to reduce greenhouse gas emissions. More information is available at www.midwesterngovernors.org/govenergynov.htm and www.midwesterngovernors.org/resolutions/GHGAccord.pdf.

As indicated throughout this report, the possibility of greenhouse gas regulations that create limits on CO_2 emissions is considered to be the largest environmental risk factor in future resource planning, including the associated costs to comply.

4.5 Major Issues

This section is a brief introduction to some of the major issues that can be expected as utilities attempt to adjust their traditional energy production strategies to satisfy the potentially major regulatory changes in the environmental area as described earlier in this Section 4. Many of these same issues appear in Section 5.6 for Renewable Portfolio Standard regulations because renewable generation is one of the means to reducing greenhouse gas emissions.

- There are presently no commercial available and economical solutions to removing carbon dioxide from fossil-fuel combustion emissions.

- The known technological solutions to removing carbon dioxide emissions from fossil fueled electricity generation have not yet been implemented on a wide scale.

- Avoiding energy usage through conservation and energy efficiency usually depends on some customer action and can only solve a part of the potential regulatory need. Similarly, cogeneration usually involves customer action and would only satisfy a part of the need.

- Nuclear generation is a zero carbon dioxide emitter, but is expected to be a fairly long-lead time option.

- Wind generation is a zero carbon dioxide emitter, but it is variable in nature and unpredictable, as well as tending toward minimum generation at high electricity load time and toward maximum generation at low electricity load time. Using wind places wind integration costs and backup generation requirements on the balance of the power system as it has to compensate for these negative characteristics of wind generation.

- Solving the wind generation backup issues with quick-start natural gas generation or a storage technology are expensive solutions.

- Sites for new hydro facilities are restricted in most cases.

- Biomass generation usually qualifies as a zero carbon dioxide emitter from the regulatory standpoint, but it has not yet been implemented on a wide scale.

- Switching from coal fuel to natural gas fuel on a large scale, thereby reducing the carbon dioxide emissions by nearly one half on a per MWh basis, would create a very large strain on an already relatively scarce fuel and drive up prices considerably.

- Generally, loads could be expected to decrease some as prices rise in response to complying with potential greenhouse gas regulations; however there might also be opposing forces that increase electricity usage under such regulation as other fuel-based activities switch to electric power, such as electric vehicles.

- Most non-emitting alternatives are either baseload-type or non-dispatchable, possibly resulting in “excess” amounts of energy being available in low-load periods.

- Nebraska's best wind generation sites are typically in low-density areas remote from urban centers thereby creating major transmission development needs for large-scale wind generation development.

- This study has made the general assumption that the cap-and-trade market system will always have allowances available at some cost. However, counting on purchasing a large number of allowances could create considerable economic risk, especially in a regulatory scenario like the ones being proposed where the total allowances granted decline over time, even as loads increase. This particular assumption has large significance in terms of risk and was found to warrant further consideration as part of the Action Plan.

- The planning uncertainties are very large both from regulatory and economic standpoints.

- The complexity of the issues and uncertainties of the variables create new challenges to the integrated resource planning modeling process. Many of these challenges have been addressed in this version of the modeling and planning process; however, it is clear that more challenges remain and future modeling versions will need to get more sophisticated.

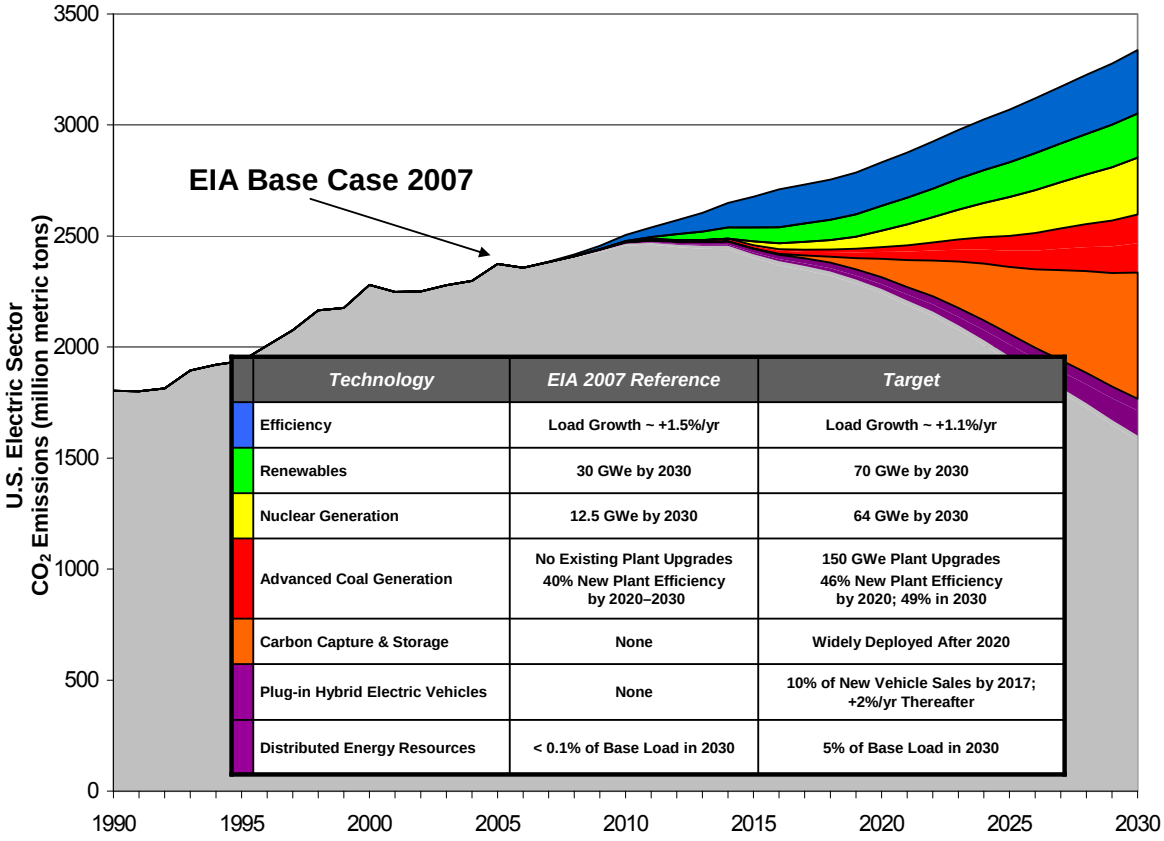
4.6 Planning Strategy

The general industry consensus appears to be that making plans to prepare for the possibility of greenhouse gas regulation (CO_2 is the major greenhouse gas) is appropriate. Further, that complying with such a regulation will be a very large task that needs many diverse contributions in order to affect a solution. The expansion plans analyzed in this study and described in Section 8.4 have considered diversity by using several resource alternatives, each contributing what it can to the CO_2 regulation scenarios. Assumptions for the study ranges for the number and pricing estimates for CO_2 allowances are given in Section 8.2.2. Similar assumptions for SO_2, NO_x, and Hg are presented in Section 8.3.4.3.

Generally, many of the same alternatives are considered in this integrated resource plan as were considered by the Electric Power Research Institute (EPRI) when it advocated for the Full Portfolio approach in its 2007 study report "The Power to Reduce CO_2 Emissions" which provides a framework to enable the electric utility sector to reduce CO_2 emissions in a substantial, yet financially sustainable manner.

Some summary details of the Full Portfolio are shown in Exhibit 4.7-1. The figure shows conceptually how EPRI's Full Portfolio of generation would look by year 2030. The horizontal axis represents time from 1990 on the left to 2030 on the right. The vertical axis represents U.S. Electric Sector CO_2 emissions in millions of metric tons. The top line is a base case situation developed by the EIA in their "Annual Energy Outlook 2007", which was not really directed toward reducing CO_2 emissions --- so these emissions continue to increase at a steady pace in that base case. The "wedges" shown in the figure consist of emission reductions that begin now, and increase enough to level the emissions starting about 2010. The resulting emissions in 2030, after these six alternatives are implemented, are roughly 45% below what they would have been in the reference EIA base case. This Full Portfolio creates about enough reductions to satisfy the stringency of the climate change legislation that is currently under discussion at the federal level.

Exhibit 4.7–1 EPRI Discussion Paper - "The Power to Reduce CO_2 Emissions": The Full Portfolio



Technology	EIA 2007 Reference	Target
Efficiency	Load Growth ~ +1.5%/yr	Load Growth ~ +1.1%/yr
Renewables	30 GWe by 2030	70 GWe by 2030
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030
Carbon Capture & Storage	None	Widely Deployed After 2020
Plug-in Hybrid Electric Vehicles	None	10% of New Vehicle Sales by 2017; +2%/yr Thereafter
Distributed Energy Resources	< 0.1% of Base Load in 2030	5% of Base Load in 2030

The added expenditures of Full Portfolio implementation, compared to a more limited portfolio, as summarized in Exhibit 4.7-1, include the following. On the supply side: Coal with carbon sequestration, expanded build-out of nuclear power, large scale energy storage which allows reliable incorporation of 20% variable-type renewable energy contributions in certain areas of the country, including the Midwest. On the demand side: accelerated improvements in electric-use efficiency and large-scale integration of plug-in hybrid within the automobile fleet. The initial expenditures for new and expensive technologies lead to later benefits for the national economy. The Full Portfolio case uses a high discount in renewable costs due to focus on development of design and manufacturing capabilities.

The Full Portfolio will cost the U.S. economy, in its movement to advanced technologies, but not as much as limiting the portfolio. EPRI estimates that the electricity rate in 2050 would be 60% less with the Full Portfolio than with a more limited portfolio.

EPRI's response to a carbon-constrained future is to develop detailed research and development action plans in the areas of CO_2 capture and storage, electrical generation efficiency improvements, advanced light water nuclear reactors, energy storage, transmission and distribution grid improvements and end-use efficiencies in areas like the plug-in hybrid electric

vehicles. In light of the EPRI studies completed NPPD has chosen expansion plans that utilize many of the same resource types that EPRI has investigated.

5. RENEWABLE PORTFOLIO STANDARD PLANNING AND COMPLIANCE

This section generally describes another potential regulation that could have significant impact on NPPD's future generation choices, although it may not cause as much impact as would stringent greenhouse gas regulation. A Renewable Portfolio Standard (RPS) could be viewed as complementary to greenhouse gas regulation, because both accomplish some of the same goals, or it could be viewed as unnecessary by some either on its face, or because greenhouse gas regulation would suffice. The planning process for renewables needs to consider the possibilities and issues associated with potentially needing to comply with an RPS, especially because oftentimes RPS legislation does not provide much lead time for facility approval and installation.

5.1 General

Scope

There are a number of renewable generation alternatives as described in Section 7.2.4. Hydro is certainly a renewable resource; however it is not always included as qualifying for an RPS. In this report, to be conservative, existing hydro generation will not be counted as qualifying for an RPS, although new (incremental) hydro could be considered as potentially qualifying. Wind generation, across the country and in this report, will be the primary alternative used to satisfy an RPS, although other alternatives have been included to a limited extent.

Planning and Compliance Perspectives

Because similar uncertainties exist for RPS as with the air emissions discussed in the Environmental Section 4, there can similarly be a benefit to planning ahead vs. waiting completely until compliance regulations are finalized. This can be true especially if one were to assume that the solutions required to meet an RPS would be some of the same solutions for satisfying greenhouse gas regulations. Wind or other renewable generation could be in that category. The expansion plans evaluated in this report contemplate renewable energy generation additions that would satisfy a range of RPS levels.

Background References and Terminology

There are multitudes of renewable references available and easily accessible on the internet. Two U.S. Department of Energy (DOE) websites include its Energy Efficiency and Renewable Energy program (www.eere.energy.gov/) and it's National Renewable Energy Laboratory (NREL) (www.nrel.gov/). These websites have lots of basic information and reports on current activities in the developing renewable energy field.

The Nebraska Power Association (NPA), of which NPPD is a member, recently published a reference document entitled "Renewable Energy Background and Outlook for Nebraska Electricity Consumers" and is available on the NPA website at www.nepower.org . This document discusses the many impacts that would result from a 15% RPS, as an example, including the investment cost and land use impacts for both the generation and transmission

expansions, as well as the operating impacts that would result from large-scale wind generation development.

The following terms typically come up in discussions concerning renewable energy generation:

> ***Biomass:*** Typically any organic matter available on a renewable basis for conversion to energy. Agricultural crops and residues, commercial wood and logging residues, animal wastes, and the organic portion of municipal solid waste are all biomass. Different Standards may have somewhat different definitions for qualifying biomass operations.
>
> ***PURPA QF:*** Public Utility Regulatory Policy Act Qualifying Facility. This federal act passed in 1978, and amended several times since, requires utilities to purchase the output of facilities that qualify under the terms included in the Act. Terms are set out for both the utility and the power producer. Small power production facilities sized 80MW, or under, usually qualify if they are renewable in nature.
>
> ***Renewable Energy Credit (REC):*** Also known as Green tags, Renewable Energy Certificates, or Tradable Renewable Certificates, RECs are the property rights to the environmental benefits associated with generating electricity from renewable energy sources. These certificates can be sold and traded and the owner of the REC can legally claim to have purchased renewable energy.
>
> ***Renewable Portfolio Standard (RPS):*** Normally this refers to a regulatory requirement that designates the amount of renewable resources needed by the utility at a given point in time. Also, an RPS is usually measured on a qualifying renewable generation's portfolio contribution to total annual electric energy consumption by the utility's retail customers.

Purpose and Impact of Renewable Portfolio Standards

The purpose of a regulatory-based renewable portfolio standard is to require a certain level of renewables in the generation portfolio regardless of other factors, such as cost or performance. Renewable energy has the benefit that it is not consuming irreplaceable fuels or, taking an energy security standpoint, relying on importation of those fuels. However, renewable generation can sometimes be more costly than traditional generation sources, depending on how one evaluates the future price escalations of alternatives or factors in the risks associated with potential regulatory scenarios, and their cost impacts, into the future over the life of the facilities.

5.2 Existing Renewable Generation Resources

NPPD's existing hydro resources in 2006, including both those owned and those from which the output is purchased, consist of approximately 161 MW of Nebraska hydro and 451 MW of WAPA hydro. From an energy standpoint, these existing hydro resources produced 304 GWh of Nebraska hydro and 793 GWh of WAPA hydro.

For NPPD's non-hydro resources, including only the portions that would be expected to qualify under an RPS, its wind generation output shares and purchased methane-fueled generation in 2006 amounted to 31.5 MW of nameplate capacity and 125 GWh of energy, which would approximately satisfy a 1% energy-based RPS.

5.3 Existing Regulations

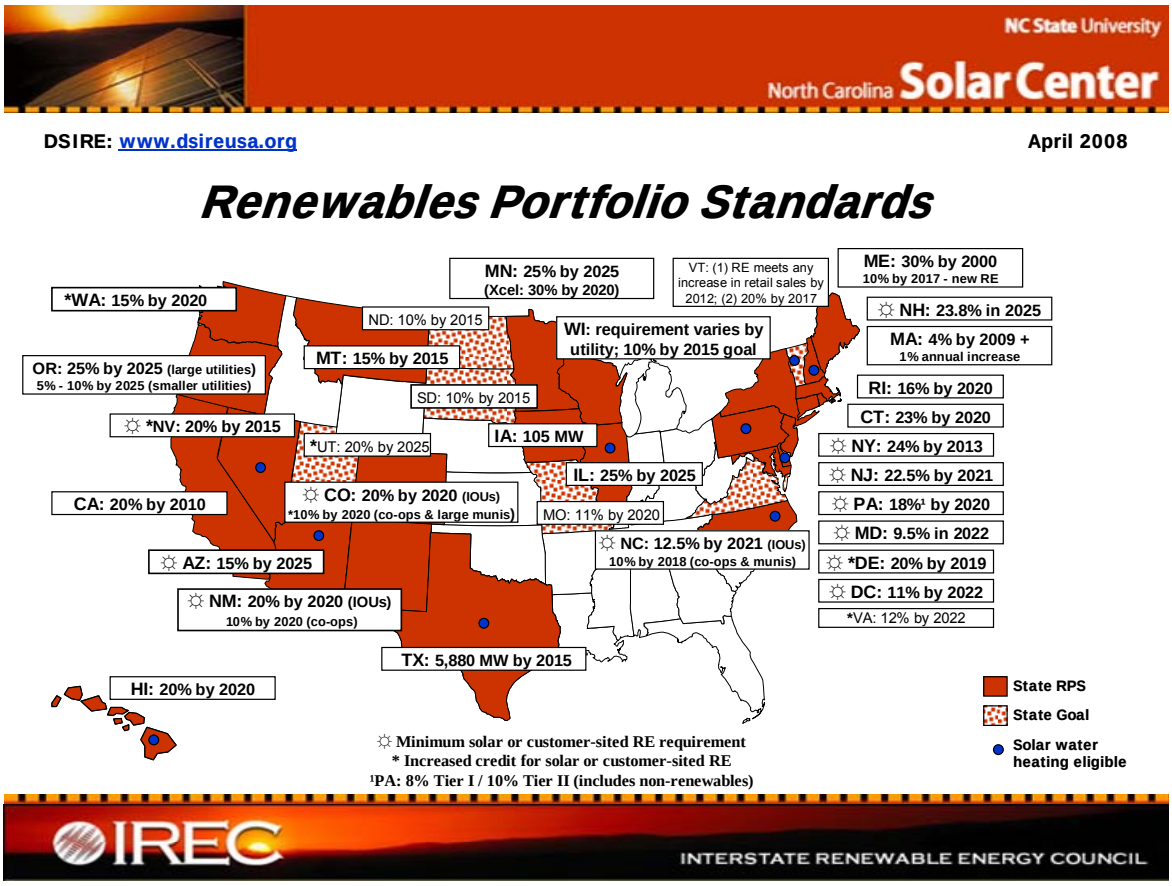
In Nebraska an RPS has not been enacted, although there have been proposals for one several times in the past. The latest version included an allowance that 25% of the standard could be met with qualifying energy efficiency program gains.

RPS legislation has been enacted in 25 states (including the District of Columbia), however not at the federal level. Six other states have renewable goals.

State level RPSs vary from a target of a few percent to 30% electrical energy from renewables. These percentage requirements are usually staged in annual increments where the final goal is to be met in a 10 to 20 year timeframe. Exhibit 5.3-1 is a map of the U.S. that summarizes enacted state RPSs[5]. More detail on a particular state's RPS, as well as up-to-date information, can be found at www.dsireusa.org.

[5] Database of State Incentives for Renewables & Efficiency (DSIRE), (a project of the N.C. Solar Center at NC State University and of the Interstate Renewable Energy Council) – "Renewables Portfolio Standards", April 2008.

Exhibit 5.3-1 Status of Statewide Renewable Portfolio Standards



5.4 Potential Renewable Portfolio Standard Scenarios

Renewable Portfolio Standards could be made applicable to NPPD by either the state or federal governments, or both. There are at least four potential general RPS scenarios with varying effects:

No RPS in the U.S. at all – Because just over half of the states already have an RPS, the only way this scenario could develop would be for the federal government to not enact an RPS, while at the same time all these states repeal such regulations, which is judged to be not likely.

Some other states have RPS, Nebraska does not, and no federal RPS – This is the current condition, which allows NPPD (a) to not install renewables or (b) to install renewables and sell RECs to any parties in the REC market, e.g., general businesses or utilities in RPS states that allow their compliance to come from renewable energy produced in other states.

Some other states have RPS, including Nebraska, but no federal RPS – This would be the condition tomorrow if Nebraska adopted a statewide RPS. NPPD would install renewables and

only be in a position to sell RECs if it produced renewable energy above the required RPS amount.

Federal RPS (A state may additionally have a state RPS, or it may do without) - Although there may be slight differences between a state RPS and a federal RPS in the definition of which renewables qualify, it would generally be expected that a MWh generated by renewables could count for both a federal and a state RPS. Again, NPPD would install renewables and only be in a position to sell RECs if it produced renewable energy above the required RPS amounts.

5.5 Position of NPPD's Strategic Plan Concerning Renewable Generation Planning

The following statement on renewable generation planning is taken from NPPD's Strategic Plan, dated February 15, 2008, and is one of NPPD's objectives designed to meet its goal of providing a low cost and reliable energy supply and delivery system:

> NPPD will evaluate all forms of renewable resources feasible in Nebraska and incorporate them in the total mix of NPPD-owned generation and contract purchases, with a goal of achieving 10% of our energy supply for NPPD's native load from renewable resources by 2020.

5.6 Major Issues

This section is a brief introduction to some of the major issues that NPPD would expect to face in its compliance with an RPS. These same issues appear in Section 4.5 for greenhouse gas regulations because renewable generation is one of the means to reducing such emissions.

- Wind generation is variable in nature and unpredictable, as well as tending toward minimum generation at high electricity load time and toward maximum generation at low electricity load time. Using wind places wind integration costs and backup generation requirements on the balance of the power system as it has to compensate for these negative characteristics of wind generation.

- Solving the wind generation backup generation resource issues with quick-start natural gas generation or a storage technology are expensive solutions.

- Sites for new hydro facilities are restricted in most cases.

- Biomass generation has not yet been implemented on a wide scale.

- Most renewable generation alternatives are either baseload-type or non-dispatchable, possibly resulting in "excess" amounts of energy being available in low-load periods.

- Nebraska's best wind generation sites are typically in low-density areas remote from urban centers thereby creating major transmission development needs for large-scale wind generation development.

- The planning uncertainties associated with renewable generation are large both from regulatory and economic standpoints.

- Economic incentives for public power entities to install renewables in Nebraska are very minor compared to those in other states or from the federal government directed to private entities.

- The complexity of the issues and uncertainties of the variables create new challenges to the integrated resource planning modeling process. Many of these challenges have been addressed in this version of the modeling and planning process; however, it is clear that more challenges remain and future modeling versions will need to get more sophisticated.

5.7 Planning Strategy

The general industry consensus appears to be that making plans that prepare for the possibility of greenhouse gas regulation is appropriate, and renewable generation is one of the potential solutions, with or without an RPS regulation. Although it is not certain which of these general scenarios for RPS will come to pass, the study ranges for RPS and the expansion plans analyzed and described in Section 8.4 generally account for the expected variation in this uncertainty. Assumptions for the study ranges for the RPS levels and REC pricing estimates are charted in Exhibit 8.2.2-3 and Exhibit 8.3.3-1. Although wind generation is expected to be the largest contributor to renewable energy development, other renewable sources are also included in the expansion plans examined as well.

6. TRANSMISSION

6.1 Transmission

NPPD belongs to Mid-Continent Area Power Pool (MAPP). A requirement of the MAPP Restated Agreement is the development of a regional transmission plan on a biennial basis. The purpose of this regional transmission plan is to integrate the transmission plans developed by MAPP members such that the transmission needs are met on a consistent, reliable, environmentally acceptable, and economic basis. It shall avoid unnecessary duplication of facilities, and shall not impose unreasonable costs on any MAPP Member. NPPD meets this requirement by participating in a coordinated transmission plan for Nebraska.

6.2 Transmission Assumptions for IRP

One of many inputs required by Transmission Planning when reviewing the reliability of the transmission system for a new unit is its location. Since this IRP did not go into the detail of location for most of the new resources, a well defined scope of what is needed for transmission is not available. But to evaluate supply side resources, all costs, including transmission should be included. To support this evaluation, transmission estimates were included, based on industry estimates, engineering judgment, and/or recently installed projects. Transmission capital costs are usually on an order of magnitude less than the capital costs of the generating unit, thus the impact of transmission cost uncertainty is not deemed to be as great as other variables.

- Peaking / Intermediate Units – The gas-fired combined cycle unit at Beatrice Power Station (BPS) became commercially operational in 2005. The transmission costs for this unit served as a starting point. It was assumed that the BPS location was ideal for transmission and could not be repeated for a similar cost. These costs were then increased due to the above and the recent price escalation of material and labor.
- Baseload Units – The overall transmission costs of OPPD's Nebraska City 2 coal-fired unit served as a starting point. A slightly higher value was utilized, using similar reasoning as above.
- Wind Units – A curve was developed, assuming that wind would be installed at the best locations first. Refer to Section 7.2.4 for details.
- Cogeneration Units – It was assumed that the output of the electrical portion of the cogeneration facility would be equal to or less than the consumption of the facility. Due to this assumption, no incremental transmission costs would be required for the cogeneration unit.

7. RESOURCE OPTIONS

7.1 General

As load grows, NPPD must add resources to continue its mission of reliable electric service. There are two general types of resources to meet new load growth:

- Supply Side Resources
- Demand Side Resources

Traditional supply side resources can be broken down into three categories: 1) Peaking, 2) Intermediate, and 3) Baseload. These resources can be dispatched to follow load when required by the system's needs. Two other less traditional supply side resources are renewable resources and cogeneration. These resources, with some exceptions, are not dispatchable.

Peaking capacity is typically defined by its relatively low capital costs and high operating costs versus other types of units. The capacity factor, the average generation output level in percentage terms, for peaking resources is commonly between 1-10%. Because of this, peaking capacity is normally used for one of the following purposes:

- Serve the incremental load during the peak time periods
- Operating reserves, mainly quick start, to respond to emergencies or forced outages
- Planning reserves

Baseload capacity is typically defined by its relatively higher capital costs and low operating costs versus other types of units. Capacity factors greater than 60% are common for baseload units.

Intermediate capacity is typically defined by its costs falling between peaking and baseload units. An example is a gas-fired combined cycle. The additional expense for the steam portion of the unit makes its capital cost higher than a combustion turbine, but lower than a baseload coal-fired unit. Its operating costs are lower than a combustion turbine since the steam cycle improves its overall efficiency, but the cost of its gas supply is higher than the fuel costs of a coal unit. Capacity factors between 15-50% are common for intermediate resources.

Renewable resources are defined by their fuel source. Two common examples of renewable resources, wind and solar, are not dispatchable since they will generate only when the wind is blowing or the sun is shining. Biomass resources use plant material as a fuel source. It is then typically fired in a more traditional steam generating unit. This allows for the unit to be dispatched.

An alternative to building supply side resources to meet higher demands is to provide incentives to the customers to reduce load. A generic name for this is demand side resources. Customers can see savings by delaying the construction of new supply side resources or by reducing the amount of fuel and other variable costs of supply side resources.

Demand side resources can either shift load from the peak period to a non-peak period, or it can reduce the load through energy efficiency or conservation. Irrigation load control is an example of shifting loads (there may also be a slight reduction in energy too). An example of energy efficiency is the use of more energy efficient air conditioners.

7.2 Supply Side Resources

Various supply alternatives were investigated as potential resources for NPPD. The screening curves in this Section 7.2 are high level cost estimates. Screening tools are limited in that it can not predict how much or when the resource will provide energy. Even with this limitation, it is very useful in providing a short list of potential projects when combined with sound engineering judgment.

When developing screening curves, it is typical to provide costs in levelized or real levelized values. The costs shown in the exhibits of this section are in real levelized costs. Section 8.1 contains a detailed explanation of real levelized costs.

7.2.1 Peaking / Intermediate

Historically, combustion turbines have been categorized as peaking units and combined cycle plants as intermediate units. Recent developments in the gas turbine industry have created high efficiency combustion turbines that possibly could compete with combined cycles as an intermediate unit. For this reason the peaking and intermediate units were reviewed together.

In developing the screening curves for peaking and intermediate resources, it was decided to pick a combustion turbine that has been shown to be economical in the industry and its size would fit within NPPD needs. An F class turbine meets these requirements. A combined cycle based on this class turbine was considered as a reasonable alternative for combined cycle technology. Costs for a General Electric LMS 100 machine were also developed. This machine is fairly new to the market and has a very high efficiency for a simple cycle.

EPRI's Technical Assessment Guide (TAG), published December 2006, capital costs ($/kW) served as a baseline for the gas-fired units. These costs were then adjusted for summer atmospheric conditions (e.g., Combustion Turbine (CT) output decreases as its inlet temperature increases and pressure decreases), gas pipeline ties, transmission, and sales tax. Operations & Maintenance (O&M) costs were based on an EPRI software program that NPPD's Energy Supply Business Unit utilizes to help them estimate future O&M costs at the BPS plant.

Costs for a pumped storage hydro plant were also developed. The capital estimate utilized a detailed engineering study from several years ago, escalated to today's dollars. These capital dollars were compared to the EPRI TAG report estimates. The $/kW costs of the two estimates are on the same order of magnitude. O&M costs were developed from hydro and pumped storage hydro facilities in the GKS database. Again, these costs were on the same order of magnitude that EPRI had estimated.

Pumped Storage Hydro technology fits best into the intermediate category. A storage technology was included in the IRP due to some of the scenarios considered where a large amount of

renewable energy is required. Presently wind is the preferred renewable resource due to its costs compared to other renewable resources, but the variability of wind and the potential it is not available during peak times could make a storage resource valuable.

In order to compare pumped storage to other resources, a cost for the energy required to refill the reservoir should be included. For the purpose of a high level comparison via a screening curve, the cost of energy required to refill the reservoir was based on off-peak market prices developed for the IRP. Pumping energy accounts for more than 50% of the cost of the storage facility.

Exhibit 7.2.1-1 provides the results of the screening process if no CO_2 costs are assumed. It indicates that a pumped storage hydro facility can be cost effective in the intermediate capacity factor range. Exhibit 7.2.1-2 provides the results if a $40/short ton of CO_2 is assumed. These exhibits indicate that the LMS 100 is presently more costly than the F class technology, even if a large CO_2 cost is assumed. This exhibit also indicates that the higher efficiency combined cycle can be more cost effective at lower capacity factors if a high variable cost of CO_2 becomes reality.

Exhibit 7.2.1-1 – Screening Curve w/CO_2 Cost = $0/short ton

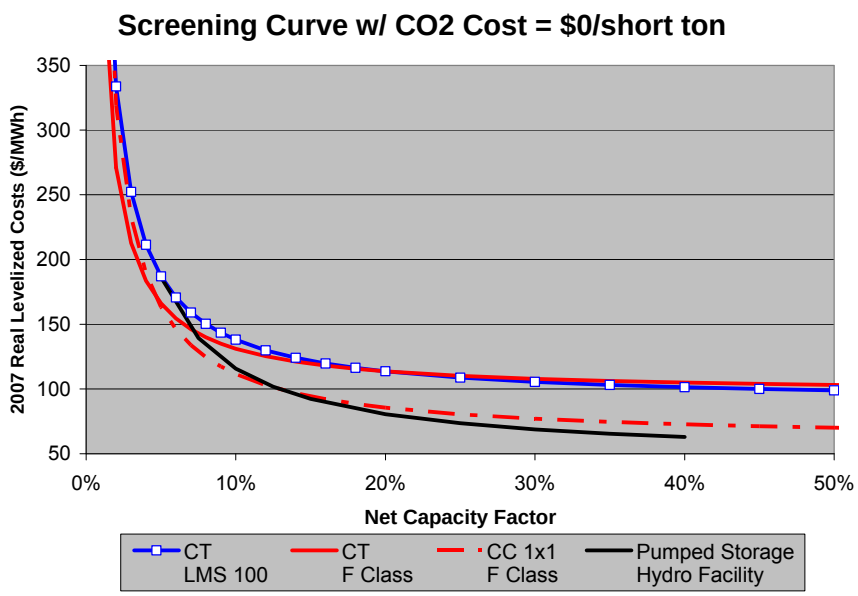
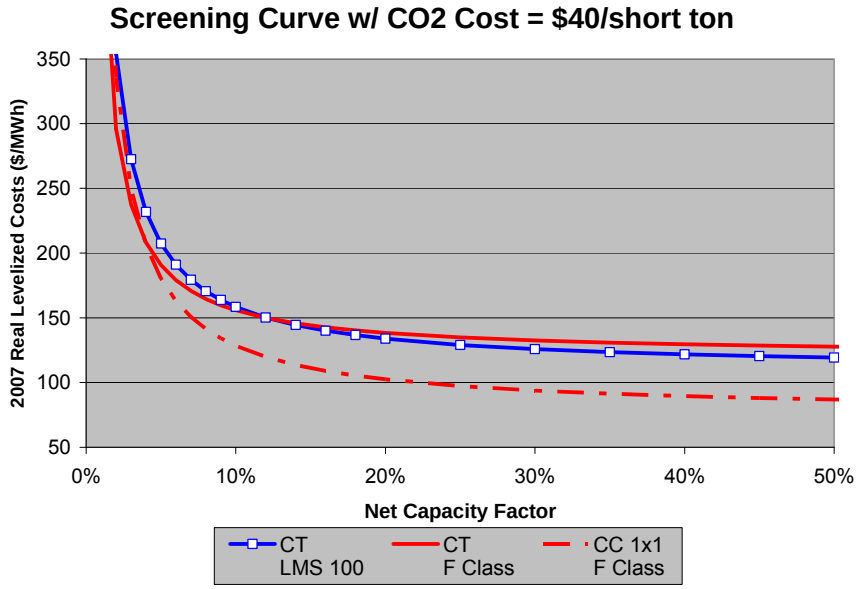


Exhibit 7.2.1-2 – Screening Curve w/CO_2 Cost = $40/short ton



7.2.2 Baseload

Baseload units using coal or nuclear fuel were reviewed. For coal, costs were developed for both super critical pulverized coal, (SCPC) and an integrated gasification combined cycles (IGCC). All units were assumed to burn Powder River Basin coal from Wyoming. A SCPC unit was chosen in-lieu of a subcritical pulverized coal or fluidized bed unit due to its higher efficiency. An IGCC unit was looked at due to its potential capability to capture CO_2 more easily than other coal units.

EPRI's TAG was used to develop the coal price information. Adjustments were made for size of the unit, fuel type, atmospheric conditions, rail spur, transmission, and sales tax. EPRI report 1014510, "Feasibility Study for an Integrated Gasification Combined Cycle Facility at a Texas Site" was used to develop costs for carbon capture for both the SCPC and IGCC units. The costs for carbon capture are highly speculative at the present time since no technology has yet been implemented to fully capture the CO_2 emissions from a utility size unit. EPRI reports were also utilized to develop costs for a coal unit with 5% biomass co-firing.

EPRI's TAG was used as a starting point for the nuclear costs. These costs were adjusted upwards based on a comparison to new coal, recent escalation of equipment and construction.

Exhibit 7.2.2-1 provides a comparison of these units when no carbon capture technology is provided for the coal units. Exhibit 7.2.2-2 provides a comparison when it is included. Even though exhibits indicate that nuclear is significantly lower than coal with carbon capture, the operational flexibility (e.g., load following) of the coal could reduce the spread if system impacts are included.

Exhibit 7.2.2-1 – Baseload Screening Curve w/CO_2 Cost = $0/short ton

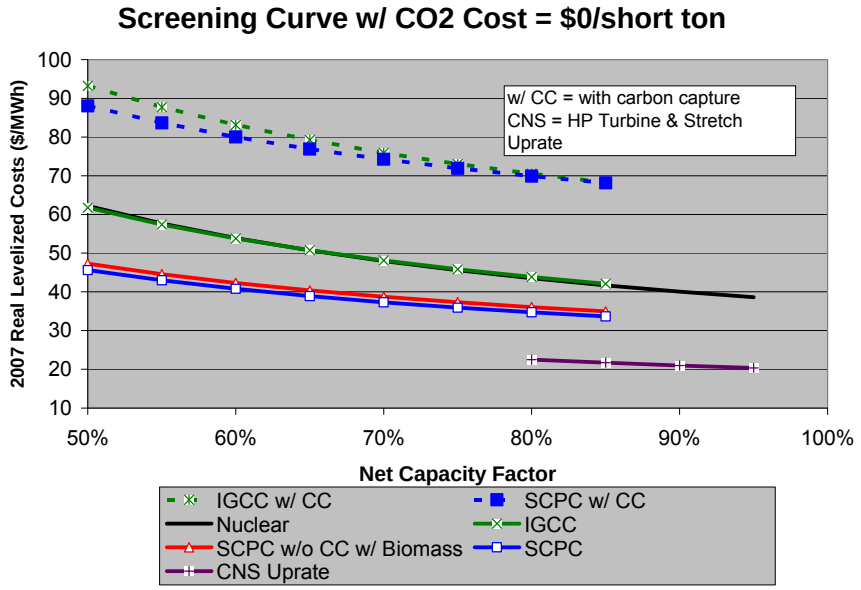
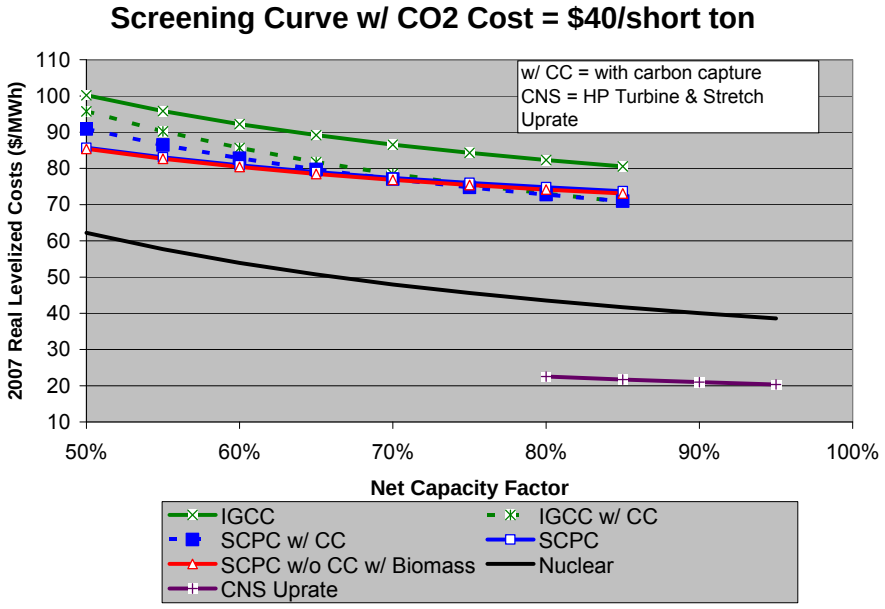


Exhibit 7.2.2-2 – Baseload Screening Curve w/CO_2 Cost = $40/short ton



7.2.3 Cogeneration

Cogeneration is the use of fuel to generate two different types of energy for end use; steam and electricity. Cogeneration can be used in industrial processes that require steam.

Exhibit 7.2.3-1 – Flow Diagram of Typical Cogeneration Facility

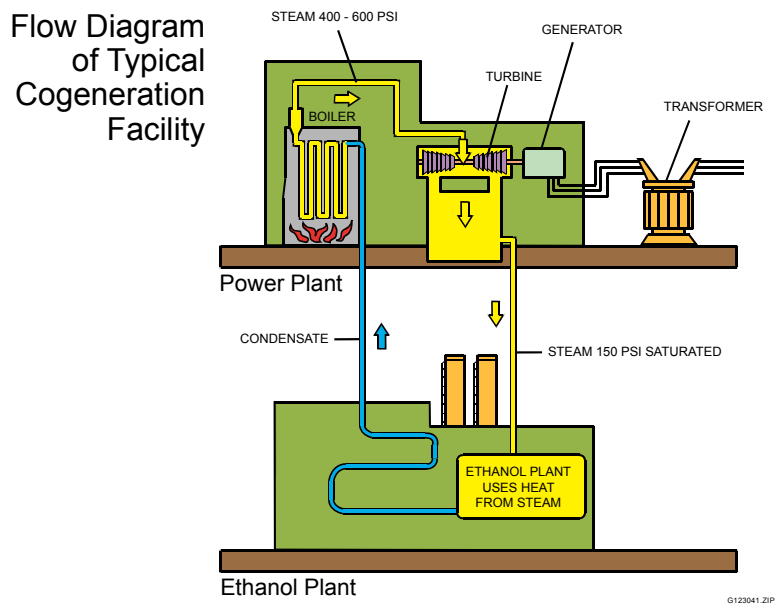


Exhibit 7.2.3-1 is a typical layout for a cogeneration project at an ethanol plant. First, the boiler creates steam from the fuel source. For cogeneration, the pressure & temperature is higher coming out of the boiler than a facility without cogeneration. The higher pressure and temperature of the steam is used by the turbine to generate electricity. The steam exits the turbine in a saturated condition at the pressure required by the process. The process then uses the remaining energy from the steam. The condensate is pumped back to the boiler to continue the process in a closed loop cycle.

This type of arrangement is called a topping turbine cycle, since the steam turbine sits on "top" of the process. This process is efficient since all of the latent heat of the steam is used. In an electrical power plant that uses steam, most of the latent heat in the steam is "thrown away" in the condenser.

When all of the steam is used in the process, the generator is not dispatchable since the amount of steam required (and thus electrical output) is dependent upon the process. To create a system where the cogeneration facility is dispatchable, a condenser would need to be added parallel to the process. This would add cost & make the generation of electricity less efficient.

The benefit of a cogeneration facility is the efficiency of the electrical generation. The incremental efficiency of the electrical generation can be on the magnitude of 60-70%, which is roughly twice as efficient as some of NPPD's steam units in operation today. As such, there are three approaches NPPD could use to utilize cogeneration:

- NPPD could sell steam from one of its plants to a third party.
- NPPD could own the electric portion of a cogeneration plant and purchase steam from a third party.

- NPPD could purchase the power generated by a cogeneration plant owned by a third party, or in-lieu of purchasing power, provide standby power to the industrial process.

Each of the above approaches would be very owner/site specific. The group formed to review NPPD's cogeneration options has concentrated on the last bullet of having NPPD purchase energy from a cogeneration facility not owned by NPPD.

Three types of fuel for a cogeneration facility have been considered by the IRP: 1) natural gas, 2) coal, and 3) biomass. The preferred approach the cogeneration group has developed for coal or biomass fuel sources is to offer the cogenerator a long term contract indexed to the General Firm Power Service (GFPS) rate offered to our wholesale customers. This would reduce the future cost risk to NPPD, our wholesale customers, and the end use customers.

For natural gas as a fuel, this approach is unlikely to work since NPPD's GFPS rate can be significantly lower than the incremental cost of gas-fired cogeneration (capital, fuel, and non-O&M costs) and the cogeneration variable costs in the off-peak hours can be greater than the incremental cost to NPPD. One approach that could be successful is to have the cogenerator operate in more of a peaking or intermediate mode with NPPD deciding whether or not to operate the unit. When the electric generation is not needed, the steam can be routed around the steam turbine via the use of a bypass valve, allowing continuous operation of the process. The unit could be economical to run during the times when gas-fired generation is setting the price. NPPD would provide a fixed revenue stream to the cogenerator to cover their capital and O&M costs, and a variable revenue stream indexed to their fuel costs. If structured properly, this type of arrangement could provide an adequate rate of return to the cogenerator, and could reduce the need for new NPPD owned peaking or intermediate generation.

The downside of cogeneration is that NPPD can not reliably plan for these additions since it is up to the industrial user if they add cogeneration to their process. Due to the confidential and proprietary nature of any agreement or negotiation, no cost information concerning cogeneration is provided in this report.

7.2.4 Renewable

Renewable projects include wind, solar, biomass, landfill gas, and new or incremental hydro facilities. The amount of additional generation available to NPPD from landfill gas or new hydro facilities is limited. For this reason, the IRP did not concentrate on these types of resources, but it should not be construed that NPPD is eliminating them from consideration. Any resource will be considered by NPPD if it is determined to be cost effective.

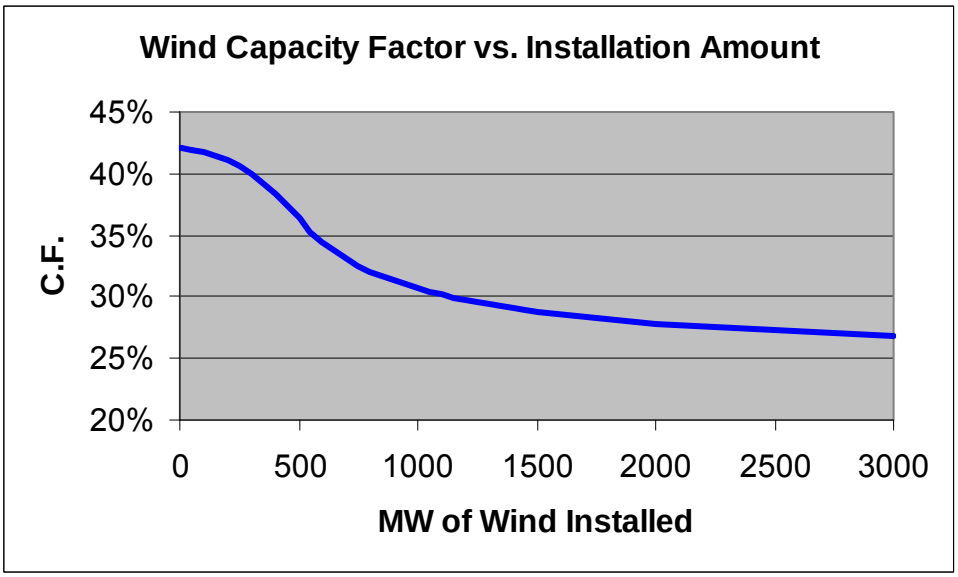
Wind has the greatest potential for a large amount of renewable generation in NPPD's service territory, and is presently the most cost effective. Various sources have indicated Nebraska is ranked as the 6th highest state in the nation for potential wind resources. The variable nature of wind is its greatest liability. Wind generation must lean on other resources when it is not operating, or operating less than predicted. This increases the overall system costs, and is referenced by the term, wind integration costs. Since there is generally an inverse correlation between wind and load, most of the wind generation can not be counted on to meet NPPD's peak

load. Finally, the best wind locations are typically away from load centers, meaning additional transmission capability is required, further increasing the cost of wind generation projects.

In developing cost curves for wind generation, each plant will be site specific. Until specific sites have been identified, some general curves are required to access its potential. Two major assumptions with variability are the capacity factor and transmission costs. It is assumed in the IRP model that the high capacity factor/low transmission cost locations will be developed first.

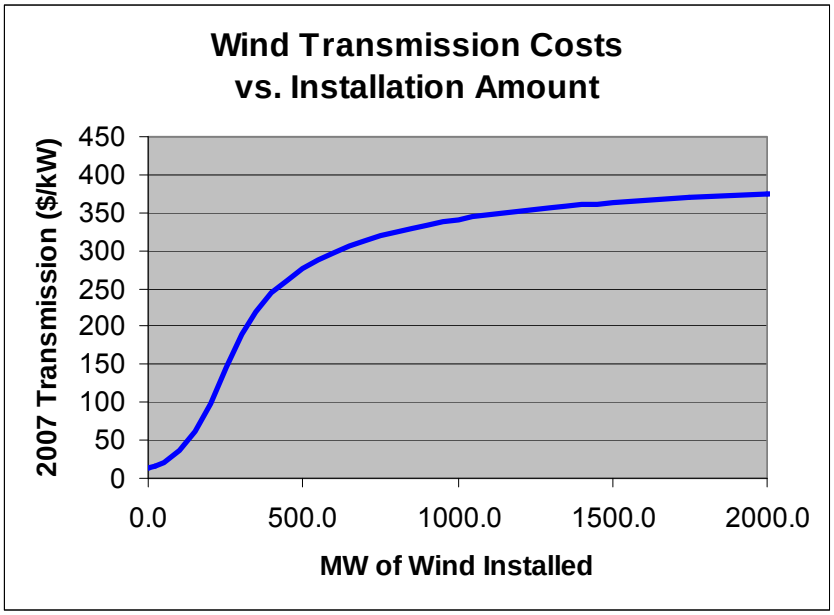
For capacity factor, it was assumed that the Ainsworth Wind Energy Facility (AWEF) site is representative of a high capacity factor site, and another instate utility's turbine represent a low capacity site. An S-shape curve was developed and is shown in Exhibit 7.2.4-1.

Exhibit 7.2.4-1 – Wind Capacity Factor vs. Installation Amount



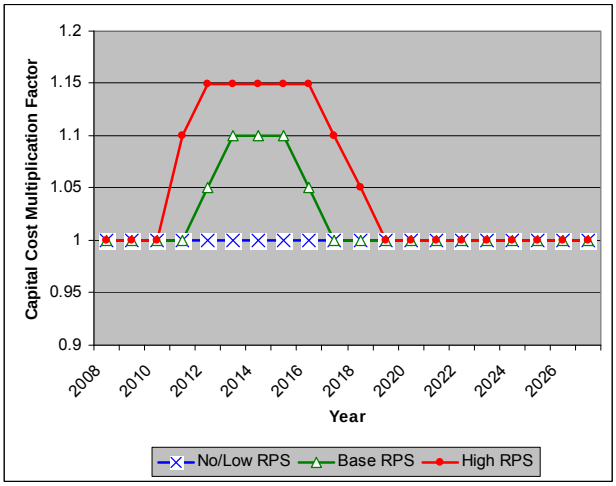
The lowest transmission cost locations would be similar to AWEF, adjusted for inflation. The highest transmission cost locations assumed 50 miles of 115 kV line and a cost of a switching station to tie into existing transmission. No transformers were assumed at the switching station. Price estimates were provided by the Project Management Office. An S-shaped cost curve was used between these two points and is shown in Exhibit 7.2.4-2.

Exhibit 7.2.4-2 – Wind Transmission Costs vs. Installation Amount



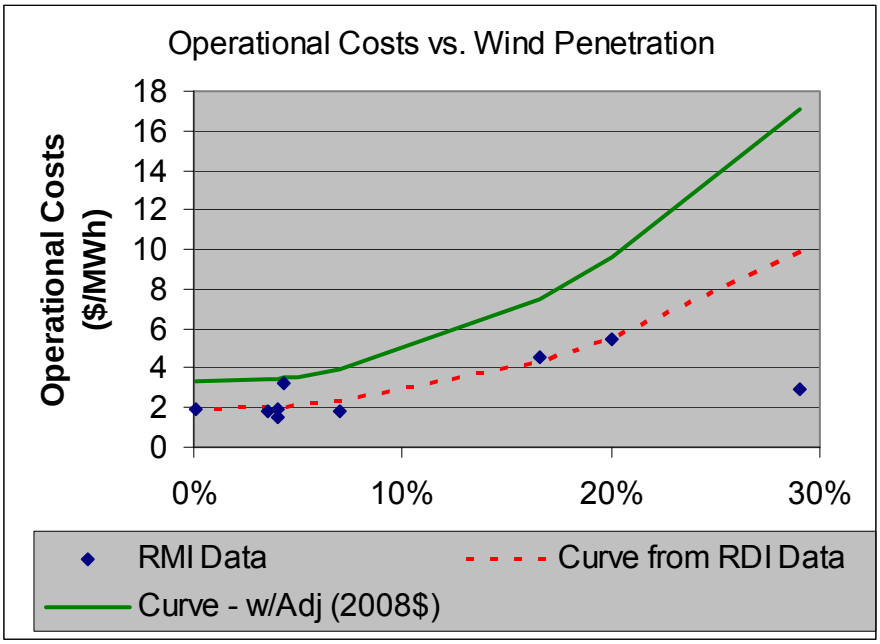
A third uncertainty regarding the cost of additional wind generation is the potential impact of future RPS requirements on the turbine capital cost. The general idea is that enactment of a statewide or national RPS requirement would increase the demand and therefore the price to procure and install additional wind turbines. Exhibit 7.2.4-3 summarizes the adjustment factors that were applied to the base capital cost assumptions to reflect this uncertainty.

Exhibit 7.2.4-3 – Capital Cost Adjustment Factor due to RPS



No detailed wind integration study has been performed for NPPD or Nebraska. A curve was developed based on data provided by a 2006 Rocky Mountain Institute (RMI) report. For wind integration, this report provided basic information from other integration studies. It was then adjusted based on a more recent wind integration study performed by the Northwest Power and Conservation Council. The results are shown in Exhibit 7.2.4-4.

Exhibit 7.2.4-4 – Operational Costs vs. Wind Penetration



Solar facilities can provide a significant amount of generation, but they are presently one of the highest cost renewable resources. Solar Photovoltaic (PV) technology is still evolving and has not yet reached mature commercial status. EPRI believes that solar PV real costs could be reduced by over 50% by 2020 due to economies of scale with larger PV sizes, manufacturing breakthroughs, and the economies of more units being sold. Its greatest asset is that its peak generation is strongly correlated to the summer peak load. Because of this correlation, its overall benefits to the electrical grid can be underestimated by a cost based screening curve.

Biomass also has potential in Nebraska. In the past, most biomass projects have used wood or the waste of wood products as a fuel. Corn stover, switchgrass, and methane recovery from animal waste are other potential fuel sources.

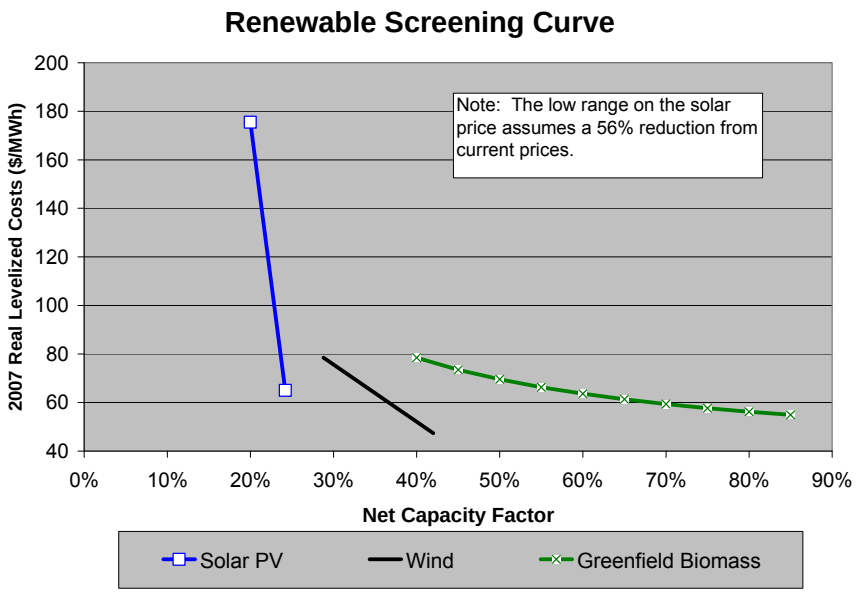
To help develop renewable resources, the federal government provides a production tax credit (PTC). The PTC presently is 1.9 ¢/kWh and will escalate with inflation. It is presently set to expire in 2008, meaning any plant built after that date will not be eligible for the PTC. Since NPPD can not use PTC, the federal government provides a renewable energy production incentive (REPI) for government entities. This incentive was originally set at 1.8¢/kWh, but it is now severely under-funded. Congress has also provided assistance to some public power renewable projects through Clean Renewable Energy Bonds (CREB). These short-term zero interest bonds were awarded to many smaller projects (under $2,500,000). A major expansion of the CREB funding would be required to support large scale utility generation projects. The IRP model presently assumes no benefits from REPI or CREB.

A market has also developed for renewable energy credits (REC). Although the present value of REC is not large, it does help offset some of the higher costs for renewable energy. There is potential for the REC value to increase if the federal government passes a RPS, or if the various

RPS of the states allow REC to be generated outside of their state boundaries. REC benefits are included in the IRP model.

Exhibit 7.2.4-5 provides a high level screening for the three renewable options discussed above. This does not include any REC or REPI revenue, and does not include integration costs.

Exhibit 7.2.4-5 – Renewable Screening Curve



7.3 Demand Side Management

An alternative to building additional supply-side (generation and delivery) resources to meet higher demands is to affect end-use customer behavior changes that result in reductions in their specific energy related requirements. These reductions can be achieved through improved energy efficiency, energy conservation, and reduced demand for energy. A generic name for these areas is demand-side resource management, and these practices have been widely used in utilities located throughout the United States for many years.

Energy efficiency refers to programs that are aimed at reducing the energy used by specific end-use devices and systems without affecting the services provided. Energy conservation reduces overall consumption of energy and/or other resources often with a reduction in services or tasks performed. Demand-side management (DSM) reduces the amount of consumer load during the time of the utility system's peak electrical demand periods.

NPPD presently has a very successful program, called the demand waiver program, to reduce summer billable peaks. The majority of savings in this program is due to irrigation load control by various wholesale customers. To investigate other DSM alternatives, NPPD contracted with Summit Blue Consulting, LLC. A copy of the report is included as Appendix E.

The overall strategy that Summit Blue Consulting used for the DSM potential study included:

- Conduct a Midwest-focused DSM benchmarking and best practices analysis.
- Develop baseline consumption profiles and initial building simulation model specifications.
- Characterize DSM measures that are appropriate for NPPD's service area.
- Conduct benefit-cost analysis of the DSM measures.
- Estimate DSM potentials for the 2008-28 period for residential and commercial customers from the successful measures.
- Develop DSM program plans based on DSM potential results.

Four tests were applied to each measure to determine its cost effectiveness in a different framework: the participant test, the utility test, the ratepayer impact test, and the total resource cost test (TRC). In line with standard industry practice, Summit Blue used the TRC test to determine which DSM programs would be most feasible to include in a portfolio of DSM measures. The general equation for the TRC test is provided below.

TRC = {(Summer Demand Savings)*(Summer Peak Avoided Costs) + (Energy Savings)*(Energy Avoided Costs)} * Measure Life / {Administrative Costs + Measure Costs}

Summit Blue evaluated 72 measures for existing residential homes and 41 measures for new residential homes. These residential measures can be categorized under the following:

- Lighting
- Heating, Ventilation, and Air Conditioning (HVAC)
- Building Envelope (e.g., insulation)
- Appliances
- Water Heating
- Demand Response

Of the 113 measures evaluated, 70 passed the TRC test in their findings. Roughly 75% of the potential energy savings came from the lighting and building envelope categories, while 70% of the potential demand savings came from the building envelope and demand response categories.

On the commercial/industrial side, Summit Blue evaluated 33 measures programs that can be categorized under the following:

- Lighting
- HVAC and Controls
- Hot Water Heating
- Custom (e.g., site specific programs not explicitly defined in the report)
- Demand Response

Of the 33 measures evaluated, 28 passed the TRC test in their findings. Roughly 80% of the potential energy savings came from the lighting and custom categories. If the irrigation demand

response was excluded, then 85% of the potential demand savings came from lighting, custom, and demand response.

Combining residential and commercial, almost 40% of the energy savings came from lighting. Of this amount, roughly ½ came from commercial measures that replaces T12 fluorescent lighting with T8 or T5. These measures also provide the single largest reduction in demand savings. Summit Blue estimated that these measures could provide roughly 20% of the total demand savings for all the programs that passed the TRC test.

To complete all programs that passed the TRC test, almost $34 million per year in today's dollars would be required for a fully developed energy efficiency program. This level of funding should be sufficient to complete all programs that passed the TRC test within a 20 year time frame. This did not include the effects of free riders, free drivers, or providing rebates multiple times for those programs with a short life, such as CFL programs. When compared to NPPD's 2007 budget, $34 million is almost 8.6% of the production revenue.

An increase of this amount for energy efficiency is unlikely in the near term. For the base case assumption in the IRP model, the Energy Efficiency and Solutions Department was consulted for a reasonable budget amount, which was then used to scale the Summit Blue results into a forecast of energy savings and demand reduction savings as summarized in Section 8.3.5.

The measurement and verification of DSM savings will ultimately depend on the programs offered. However, some programs may use deemed savings based on accepted industry standards, while other programs may use simplified calculations based on equipment data and or statistically sampled metering. Customized programs, such as industrial process retrofit, may involve full measurement and analysis.

8. MODELING APPROACH

8.1 General

NPPD's mission is to, "Safely generate and deliver low cost, reliable energy and provide outstanding customer service". To help meet the mission requirement of reliable energy, a sufficient amount of resource capability must be available to serve the anticipated load. NPPD is a member of the Midwest Reliability Organization (MRO). The MRO has proposed a reliability standard, RES-501-MRO-1, "Generation Planning Reserve Requirements". In the standard the MRO has proposed that each load serving entity, or its delegate, perform a loss of load expectation (LOLE) study annually. The LOLE shall not exceed 1 day in 10 years.

As stated previously, NPPD also belongs to MAPP. In the MAPP Generation Reserve Sharing Pool Handbook, Revision January 16, 2007, it states, "Predominately thermal systems shall maintain a 15% Reserve Capacity Obligation." This basically means that the amount of resources shall be at least 15% greater than the utility's peak load. This reserve capacity obligation has met the 1 day in 10 years criteria in the past. MAPP has indicated that it will perform or contract to perform a LOLE study for the MAPP members to meet the MRO requirements.

In the past, if the after-the-fact surplus/deficit calculation showed a deficit for a utility, an assessment for the deficit capacity (Schedule B) was applied and the cost paid by the deficit member to the MAPP members that had sufficient reserves. In order to minimize NPPD's chances of paying this assessment, NPPD typically plans to meet the reserve requirement during a hot, dry summer, defined as a severe weather condition. For purposes of the IRP study, NPPD will assume that the 15% reserve requirement adequately meets the MRO standard. Each resource plan NPPD develops will meet the 15% reserve requirement under severe weather summer season[6] conditions.

To meet the mission requirement of low cost energy when analyzing the impacts of various resource options, a method of evaluation must be used. Standard NPPD and utility practice is to use the net present value (NPV) to evaluate the different costs. NPV is an economic analysis method that compares one series of cash flow to another, taking into account the time value of money.

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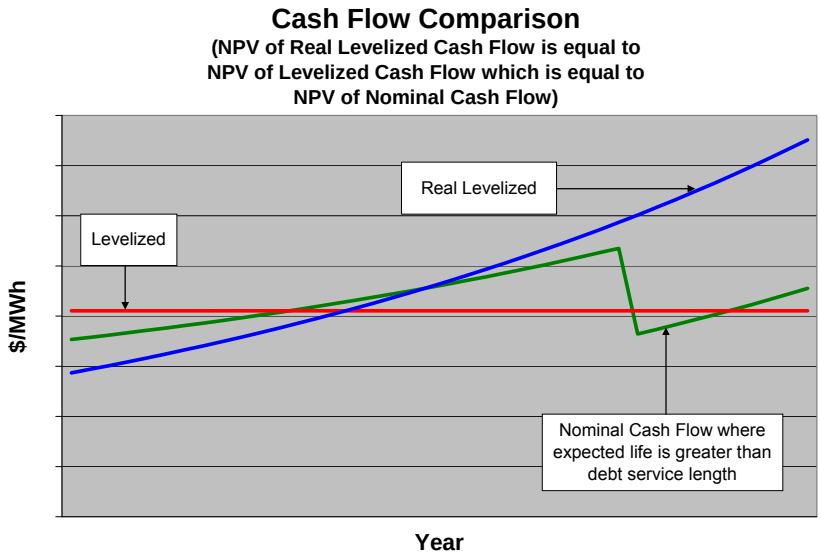
[6] Historically, NPPD's peak demand during the summer season has been higher than during the corresponding winter season. For this reason, the focus of this IRP has been to ensure that NPPD has sufficient resources to meet firm capacity obligations during summer peak conditions. In the current IRP model, load and capability calculations are only considered for the summer season. Nevertheless, projected load and capability graphs for both the summer and winter seasons, and considering only existing/committed resources, have been included in Appendix C as **Exhibit C-1** for the summer season and **Exhibit C-2** for the winter season. These graphs indicate that surplus capacity during the winter season is projected to be comfortably higher than the corresponding summer season over at least the first half of the study. By the end of the study period (2027), however, the requirements for additional capacity resources during the winter season are forecast to be similar to those in the summer season. This trend of a more balanced firm capacity obligation between summer and winter is one that NPPD will need to continue to monitor in future IRPs.

When utilizing the NPV method, future cash flows are adjusted by means of a discount factor. This discount factor is typically the cost of money for the entity. NPPD currently uses the projected interest rate of the bonds issued by NPPD to fund the project as the cost of money. The resource plan with the least amount of NPV costs will provide our ratepayers with the lowest cost over a long term period.

In some of the exhibits in this report, the real levelized costs of the options were calculated. Other utilities may use levelized costs. What are these costs and why are they used? A levelized cost is simply a constant cost, or rate for the entire economic life of the unit and the NPV of this uniform series is equal to the NPV of the nominal costs of the option. Real levelized is a cash flow series that escalates at the nominal rate of inflation (i.e., the "real" cost stays constant), and its NPV value is also equal to the NPV of the nominal costs of the option. The exhibit below provides a simple example.

Exhibit 8.1-1 – Cash Flow Comparisons



The levelized or real levelized value is useful when comparing different projects with different fixed and variable costs. The nominal costs of the various options can then be reduced to a single value for each assumed capacity factor, allowing a reasonable "apples-to-apples" comparison between the options.

If the future could be predicted with absolute certainty, then one NPV cost could be calculated for each resource plan, and it would be straight forward to pick the lowest cost plan. Since the future is by definition uncertain, NPPD included uncertainty in the IRP model to better represent the range of costs for each resource plan. The major variables and scenarios modeled are detailed later in this section.

8.2 IRP Model

8.2.1 Development

The IRP model was designed such that it would be capable of:

- Modeling uncertainties of a number of variables, including fuel, market prices, load growth, capital, and operating costs.
- Modeling different carbon and renewable portfolio scenarios to represent possible regulatory futures.
- Modeling numerous types of new units and resource plans.
- Providing a reasonable estimate of generation of new and existing resources.
- Analyzing the different resources plans under the different scenarios and uncertainty distributions using Monte Carlo draws.
- Providing a range of NPV values based on the scenarios, resource plans, and variables outline in the model, along with the annual revenue requirement for each year in the study period.

8.2.2 Regulatory Scenarios

Two regulatory uncertainties were determined to have a major impact on the future; 1) carbon regulation, and 2) renewable portfolio standards. Although presently there are no carbon constraints or RPS laws that NPPD must meet, it is expected some type of regulation may be required in the future. The IRP model uses a "switch" to toggle between a no carbon constraint / no RPS laws to the scenarios with these uncertainties included.

In the model, increasing RPS requirements were positively, but not fully, correlated with increasing CO_2 cost. Some runs were made for a No CO_2 cost / No RPS law scenario for informational purposes and presented in Section 9.4, although that scenario was not weighted in with the other scenarios for weighted or overall expected value results. Note that "No RPS" terminology means that no RPS law is applicable to Nebraska; although a low range of REC prices still exists, as is the case today, and is modeled that way.

A brief discussion of each scenario is provided below.

Carbon Constraints

Some background on the importance of uncertainties regarding carbon regulation is described in Section 4. Three different scenarios, low, base, and high were modeled. The Climate Change / Greenhouse Gas Regulation Team, along with a consultant, reviewed proposed federal laws, regulations developed in California, the Northeast States, and the world.

It was decided to model the scenarios using a cost for the amount of CO_2 emitted, and allowing for some of the utilities emissions to be "free". If a certain resource plan exceeds the number of "free" allowances, then the IRP model will buy the appropriate number of allowances.

Conversely, if the number of "free" allowances exceeds the resource plan's emissions, then the IRP model will sell the extra allowances, lowering the cost of the resource plan.

Please note that the number of "free" allowances will not have an impact on which resource plan has the lowest NPV cost. For example, if resource plan "A" emits 10,000,000 tons per year of CO_2 and resource plan "B" emits 12,000,000 tons per year of CO_2, plan "B" will be required to pay for 2,000,000 more tons per year of CO_2 allowances. It does not matter whether the number of "free" allowances is 0 or 10,000,000 tons, plan "B" will still require to purchase 2,000,000 more tons of CO_2 than plan "A" (or sell 2,000,000 less tons than plan "A" or some combination of buying and selling).

The number of "free" allowances does have an impact of the projected cost of electricity. Let's assume the cost of CO_2 is equal to $10/ton, and no "free" allowances are allocated. In this case, plan "A" would be required to pay $100 million per year for emitting CO_2, while if 10,000,000 tons are "free" the cost for plan "A" to emit CO_2 is zero. This example clearly shows that the number of "free" allowances can have a significant impact on electricity rates.

In 2006, the total amount of CO_2 emitted at NPPD's power plants was just under 13.3 million short tons. From 2001-06, the annual CO_2 emitted averaged under 13.4 million short tons. These amounts do not include any CO_2 emissions from purchases made in these years. Note that in this report, historical emissions are listed in short tons, as required for federal government submission; whereas, model results are given in metric tons (=1.1 short tons), as is common industry practice. The rationales for the three carbon regulation scenarios are:

- Low – Assume a slight reduction in the GHG intensity, although the GHG emissions continue to grow. This scenario is based on the policies recommended in 2004 by the National Commission on Energy Policy and includes a safety valve. A start date of 2014 was assumed.
- Base – After a review of a number of legislative bills, including Bingaman's, a start date of 2013 was assumed with the price starting at $12/metric ton and increasing by 5% per year in real terms.
- High – This scenario was developed by a combination of the more stringent regulatory proposals that would reduce CO_2 emissions below 2005 levels by 2025. The allowance price was based on analyses from the EIA, Massachusetts Institute of Technology (MIT), and other entities. A start date of 2012 was assumed.

Exhibit 8.2.2-1 – CO_2 Cost Assumptions

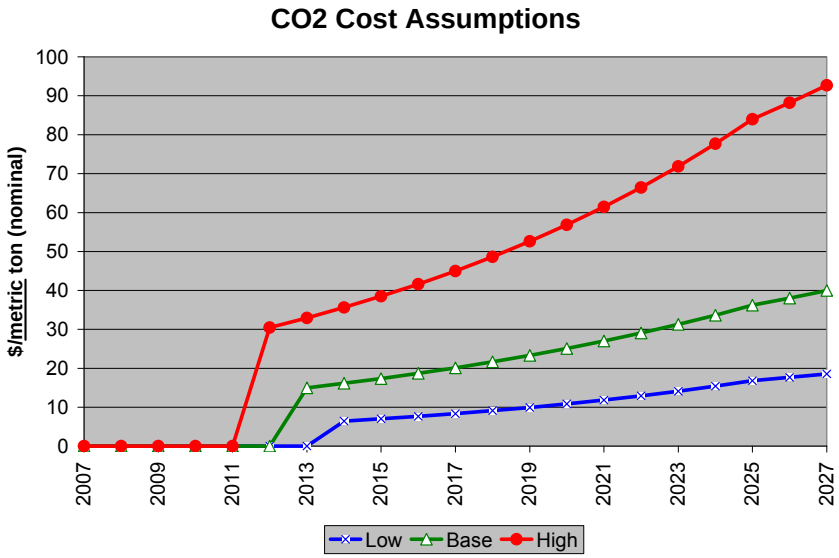
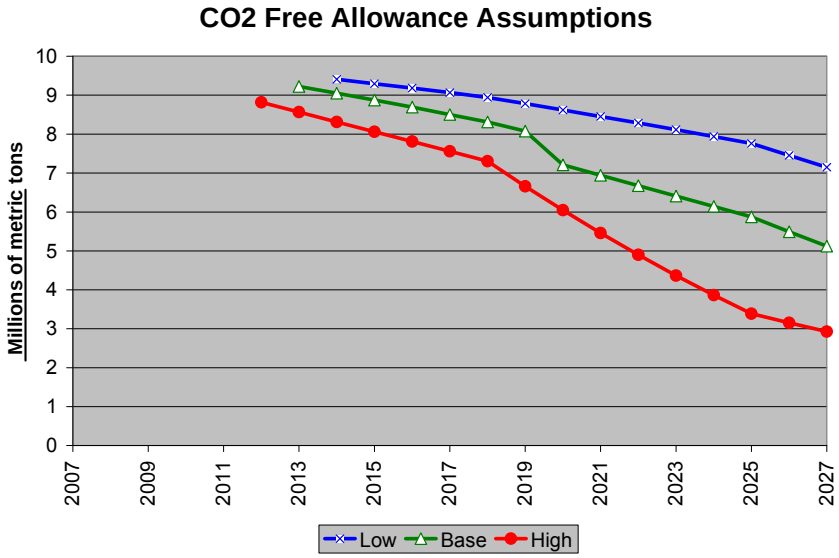


Exhibit 8.2.2-2 – CO_2 Free Allowance Assumptions



Renewable Portfolio Standards

A Renewable Portfolio Standard may be applicable to NPPD at some point in the future as described in Section 5. The rationales for the three RPS scenarios are:

- Low – A RPS requirement of 5% by 2016. Lower rate of increase after 2016.
- Base – RPS is assumed to gradually increase. In 2019, renewable generation equal to 10% of native load was assumed, based on a bill in the 2007 Nebraska Legislature. Continue to increase after 2019, but at a slightly lower rate.

- High – A RPS requirement of 30% is required by 2025. A high amount of renewables would be required to meet any significant CO_2 reductions. There are bills/laws in other states and the federal government that have RPS values between 20-30%.

Exhibit 8.2.2-3 – RPS Requirement as a Percent of Native Load

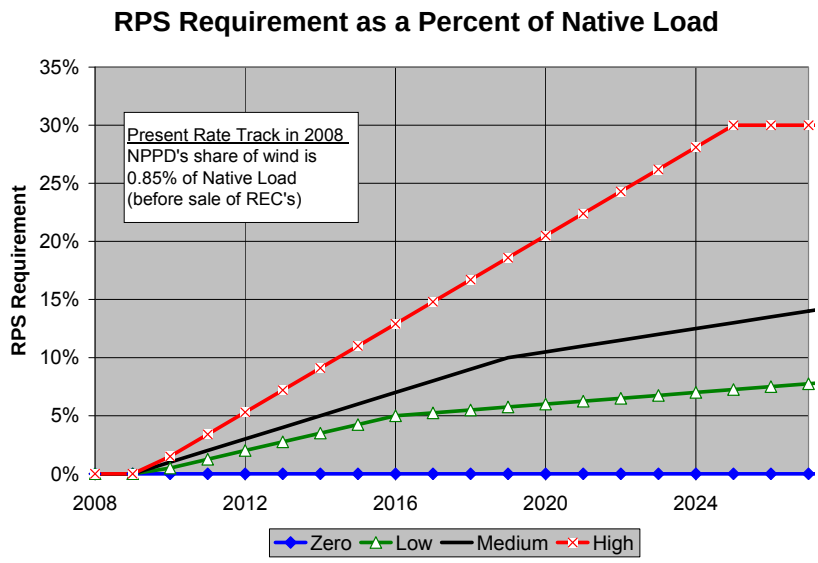
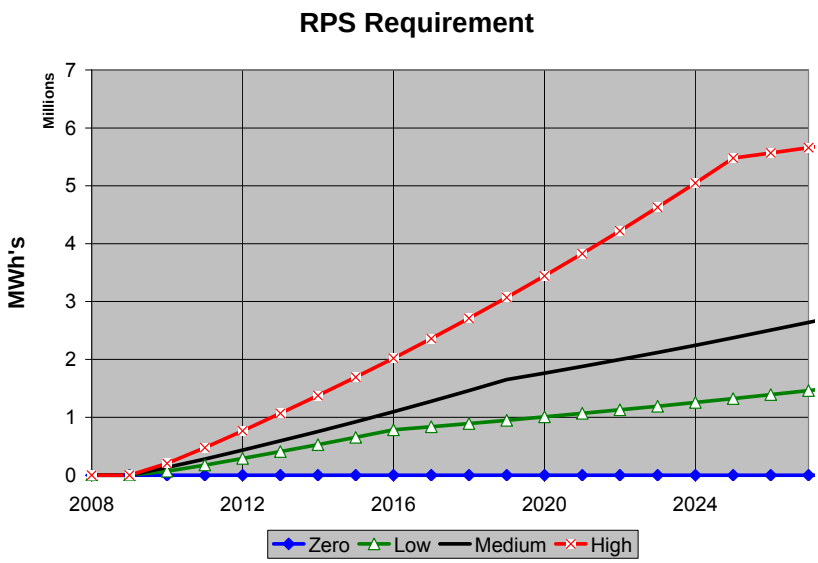


Exhibit 8.2.2-4 – RPS Requirement



8.2.3 Verification

One of the fundamental requirements for the model is the ability to provide a reasonable estimate of annual generation from existing and new resources over the study period. In past studies NPPD used commercially available software, PROMOD[7], to develop the annual generation

[7] PROMOD IV® production modeling software is licensed from NewEnergy Associates, LLC (now Ventyx Energy)

projections, which were then transferred to a spreadsheet model for additional analysis. For purposes of the IRP analysis, a high level method for projecting unit generation was developed that could be implemented directly in the IRP spreadsheet model[8]. Because of the importance of having reasonably accurate generation projections, a number of multi-year comparative PROMOD simulations[9] were conducted in order to benchmark the IRP model to the PROMOD dispatch results. Of particular interest was the impact on the level of non-firm sales with significant additions of non-dispatchable generation (such as wind) and how those impacts would change with the addition of energy storage units. Initial comparisons indicated that the IRP Model tended to underestimate non-firm sales energy[10], relative to PROMOD results, for these cases. Using the results from the PROMOD simulations, regression analyses were performed to develop polynomial equations[11] relating non-firm sales amounts to native load, non-dispatchable generation, dispatchable baseload generation, and storage unit energy (both pumping and generation).

In the IRP model, these equations were used to estimate the non-firm sale amounts for each year of the study period and unit generation was then adjusted to bring it into balance with the forecasted load. Using this modified approach, energy sales and unit generation projections in the IRP model were brought into reasonable alignment with the PROMOD simulation results. A more detailed discussion of the model verification process is included in Appendix F.

8.3 Major Variables Modeled

Based on previous studies, industry literature, and engineering judgment, the following paragraphs in this section cover those items that were considered to have the greatest uncertainty and/or the greatest impact on NPV if their assumptions change.

8.3.1 Load Forecast

The major uncertainty surrounding the load forecast in the near future is the additional industrial load, mainly ethanol production facilities that may be installed in NPPD's service territory. The long term uncertainty is based on the socioeconomic variables that are discussed in Section 3.

[8] The high level dispatch methodology was implemented as a Microsoft® Visual Basic program incorporating the Microsoft® Excel Solver tool to balance generation, purchases, and sales with forecast load on an annual basis.
[9] Four basic PROMOD cases were developed, generally corresponding with the Min1, Mod1, Ext1, & Ext2 resource plans.
[10] Two main categories of non-firm energy sales are estimated in the IRP model, in order to more closely track the PROMOD simulation results: 1) General non-firm sales, which are priced based on the assumptions discussed in Section 7.3.6; and 2) Dump energy sales, which represent unavoidable surplus must-run minimum segment generation that cannot be used by NPPD for its own requirements. As is the case in PROMOD, this dump energy is priced at a nominal rate of $5.00/MWh, which is significantly below the normal 7x24 market price assumptions.
[11] Separate equations were developed for projecting general non-firm sales and dump energy sales.

Exhibit 8.3.1-1 – Billable Peak Forecast

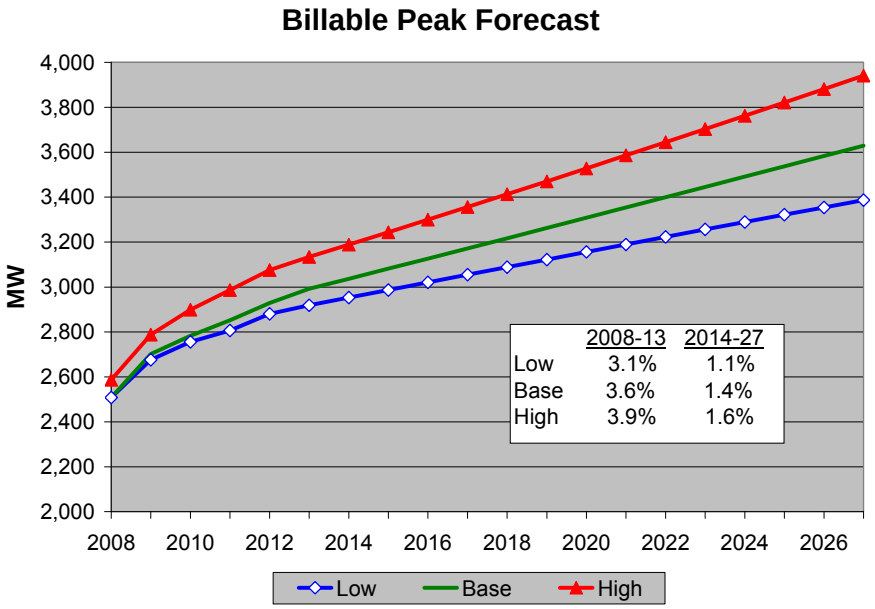
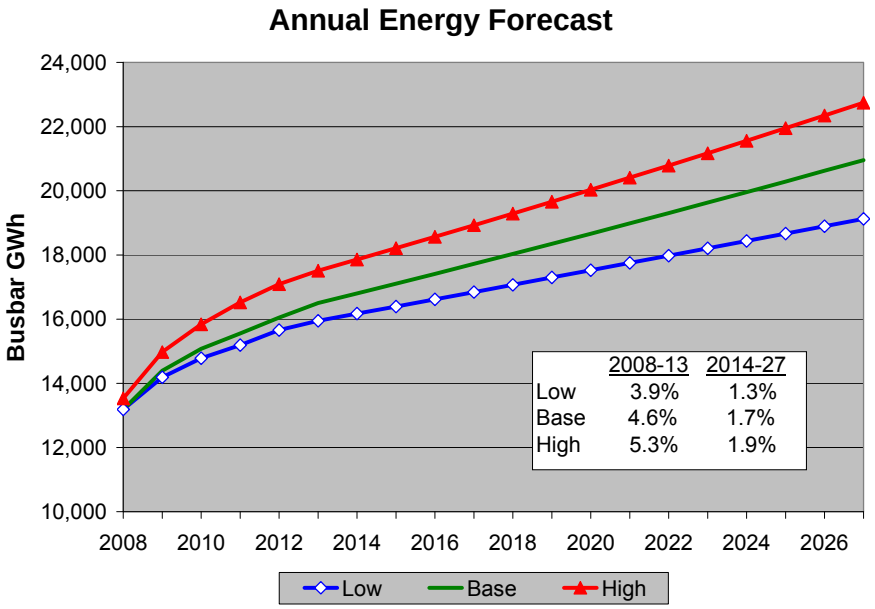


Exhibit 8.3.1-2 – Annual Energy Forecast



8.3.2 Supply Side Resources

8.3.3 Capital and O&M Costs of New Units

Generally, there is more upside risk in the capital costs when building new units. Not accounting for all requirements, firms being busy and not providing bids are just two reasons the prices tend to be skewed to the high side.

The smallest price ranges for capital costs are for gas-fired combustion turbines and combined cycles since these technologies are mature and there have been a number of utility installations over the past few years. The range assumed was from a -10% to a +15% difference from the base assumptions. Wind, biomass, and coal units without carbon capture had a slightly larger range, -10% to +20%. Nuclear, pumped hydro storage, and coal units with carbon capture were larger yet (-10% to +30%) due to either being an immature technology or the absence of units recently built. Solar had the largest range since the base cost assumed that the capital cost for solar would drop considerably from today's cost based on its technology maturity. Solar resources are assumed to have a capital cost range from -10% of base to +50% of base.

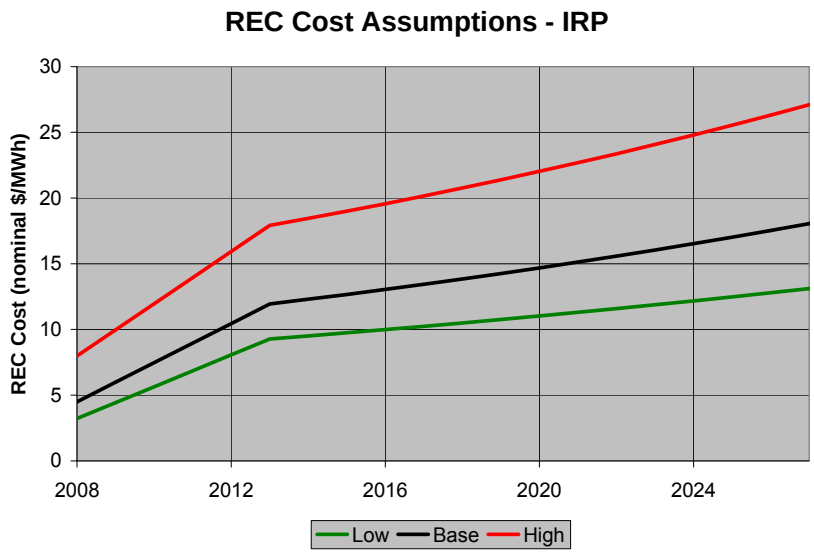
The price range differences between the various options are more critical than the absolute price range in measuring the relative risk of each option. O&M costs were also modeled with price ranges. The O&M costs generally followed the same ranges as the capital costs.

8.3.4 Renewable Portfolio Standards

The uncertainties surrounding the RPS were modeled as scenarios. The scenarios are detailed in Section 8.2.2 of this report.

REC prices were also allowed to vary with the RPS. The price of REC was assumed to be correlated to the RPS, that is, a high RPS would translate to high REC prices. Per RMI's GHG Strategy report (2005), the voluntary market REC are in $2-$6/MWh price range and the compliance market is in the $8-$15/MWh range (in 2007 dollars). It was assumed that the compliance market rates (nominally escalated) are fully implemented by 2013. Refer to Exhibit 8.3.3-1 below for the REC price range.

Exhibit 8.3.3-1 – REC Cost Assumptions – IRP



8.3.5 Environmental

8.3.5.1 Approach used in the IRP Model

The approach used in the IRP model to represent emission costs is a market-based cap-and-trade system as described in Section 4.1. Allowance costs for four major air pollutants were estimated, 1) CO_2, 2) SO_2, 3) NO_x, and 4) Hg. In addition to the allowance cost, the number of free allowances, or those that are provided to NPPD from the government without cost, was also estimated. If NPPD required more allowances than the allowances provided free, the model assumed NPPD would go into the market and purchase the amount necessary. These costs were added to the wholesale revenue requirements. Conversely, if NPPD had more free allowances than what was required in a year, the excess allowances were sold to the market.

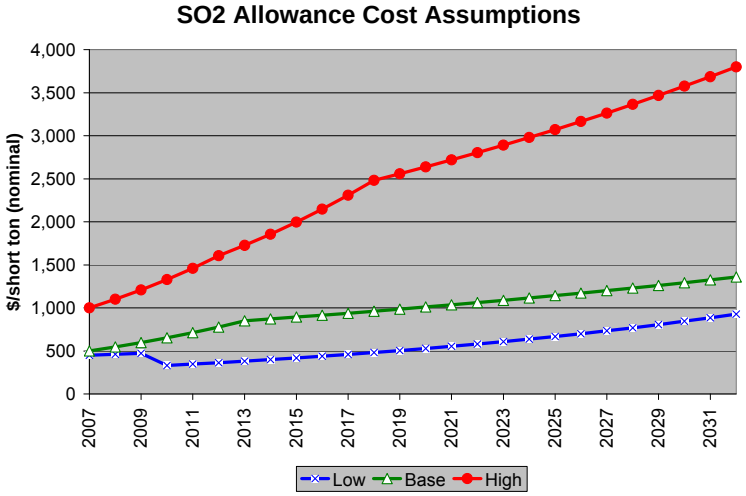
8.3.5.2 CO_2 Cost

The uncertainties surrounding the CO_2 costs were modeled as scenarios. The scenarios are detailed in Section 8.2.2 of this report. In addition to the allowances, the IRP model assumed that 20% of the CO_2 allowances required annually could be met with offsets, and that the offset price would average 80% of the CO_2 allowance price. Examples of offsets would include tree planting, no-till farming, methane capture of animal waste, etc. In addition to NPPD owned units, the IRP model also includes an estimate of CO_2 emissions associated with long term purchases when projecting NPPD's annual emission total.

8.3.5.3 SO_2, NO_x, & Hg Cost

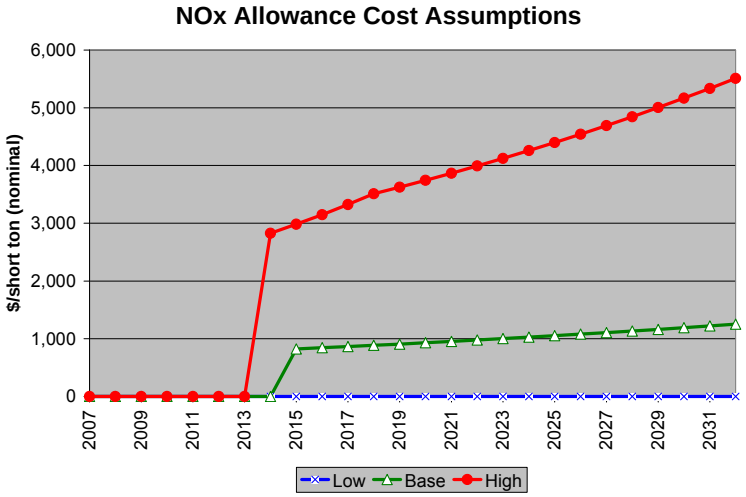
The base price for the SO_2 costs were based on the CAIR assumptions from GED's market forecast. The long term high price was based on a multiple of the estimated cost of SO_2 removal at GGS. The low price case assumes that the market stays relatively flat in real terms. These estimates were reviewed by the Corporate Environmental Department.

Exhibit 8.3.4.3-1 – SO_2 Allowance Cost Assumptions



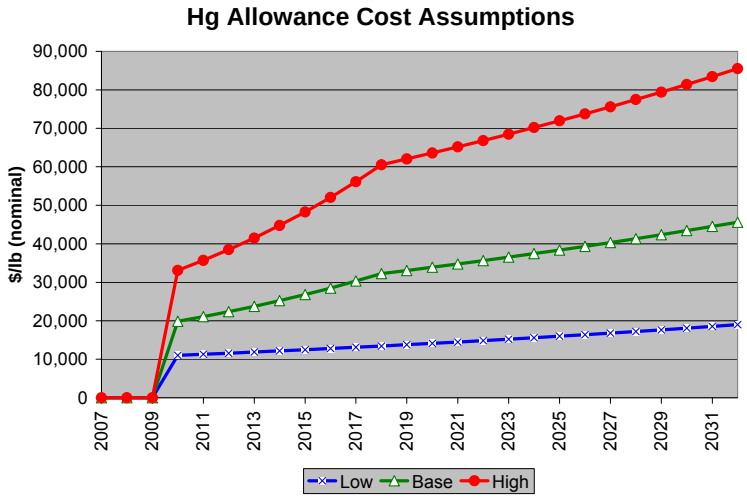
The low price case for NO_x assumed that Nebraska would not be required to trade for NO_x allowances. The base price was based on the CAIR assumptions from GED's market forecast. The long term high price was based on a multiple of the estimated cost of NO_x removal at GGS. These estimates were reviewed by the Corporate Environmental Department.

Exhibit 8.3.4.3-2 – NO_x Allowance Cost Assumptions



The high and low prices for Hg were provided by the Corporate Environmental Department. The base price case was assumed to be slightly skewed to the low price case.

Exhibit 8.3.4.3-3 – Hg Allowance Cost Assumptions

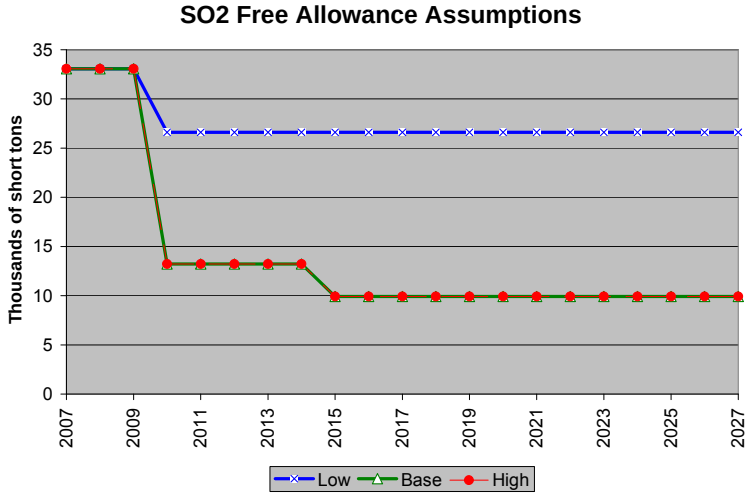


8.3.5.4 Allowances

The free allowance assumptions are correlated to the price assumptions. That is, the low allowance assumption case is used with the low price assumptions, the base allowance assumption case is used with the base price assumptions, and the high allowance assumption case is used with the high price assumptions. Due to this naming convention, the low allowance assumptions will have more free allowances than the base or high cases.

For SO_2, the low allowance case assumes that the current acid rain program limits continue. For the base and high case, the GED estimate of 60% reduction of current levels by 2010 and 70% reduction by 2015.

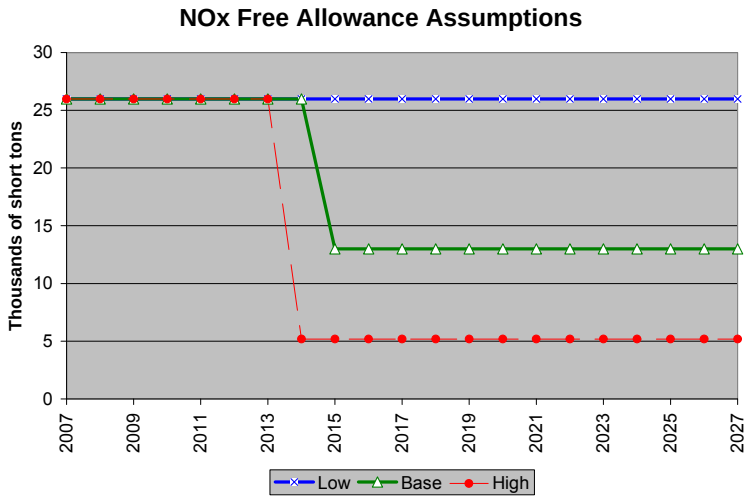
Exhibit 8.3.4.4-1 – SO_2 Free Allowance Assumptions



For the low allowance NO_x case, the IRP model assumes that no cap and trade program exists, thus the number of free allowances was set to an arbitrary value that is equal to or higher than the number of allowances presently produced at NPPD generation facilities. For the base case, a

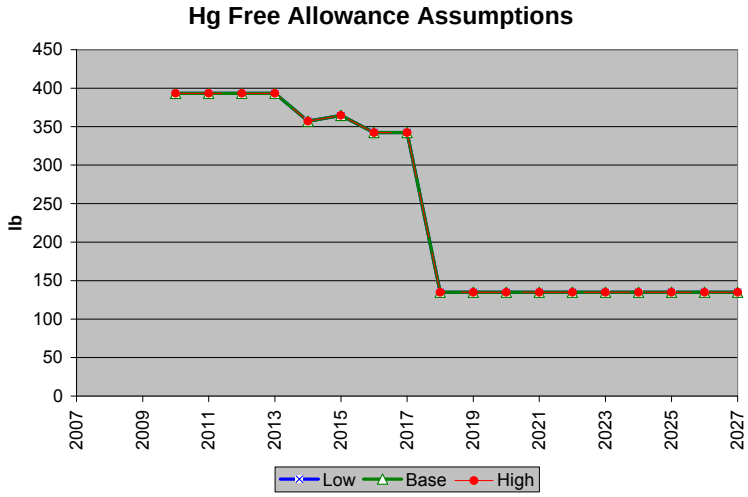
reduction relative to current levels of 50% starting in 2015 was assumed. For the high case, a reduction of 80%, relative to current levels starting in 2014 was assumed. These assumptions were based on conversations with NPPD's Corporate Environmental Department.

Exhibit 8.3.4.4-2 – NO_x Free Allowance Assumptions



For the free allowances for Hg, the assumption on the number of free allowances is based on an interpretation of proposed State of Nebraska program from Corporate Environmental. Prior to 2010, no Hg costs are assumed, thus the number of free allowances are immaterial.

Exhibit 8.3.4.4-3 – Hg Free Allowance Assumptions



8.3.6 Energy Efficiency Savings and Costs

The Energy Efficiency and Solutions Department was consulted on the ranges to use in the IRP model. The base case assumed that once fully implemented, that the size of the budget for energy efficiency programs would be approximately $7.5 million per year in today's dollars, and the amount of energy saved was based on this amount. The high case assumed that NPPD could see efficiency savings similar to what the Northwest Power and Conservation Council told

NPPD on recent visits. This amounted to energy savings of approximately 40% of the new load growth. The Energy Efficiency and Solutions Department agreed that one third to one half of the base case energy savings was reasonable for the low case.

Exhibit 8.3.5-1 – Annual Energy Savings

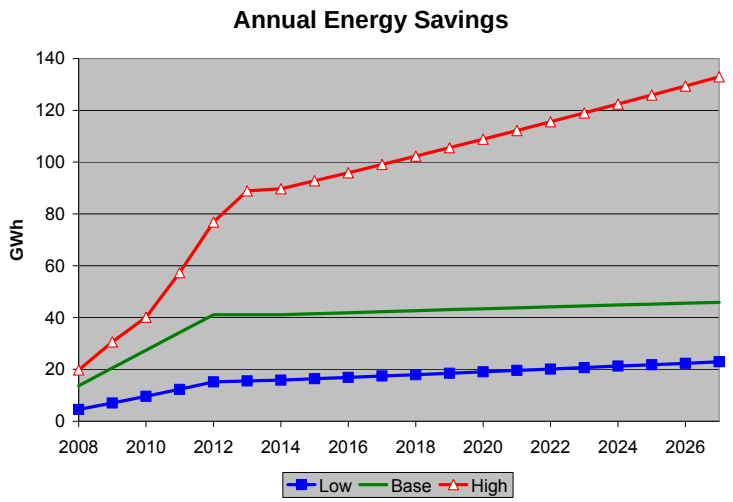


Exhibit 8.3.5-2 – Annual Energy Savings as a Percent of Load Growth

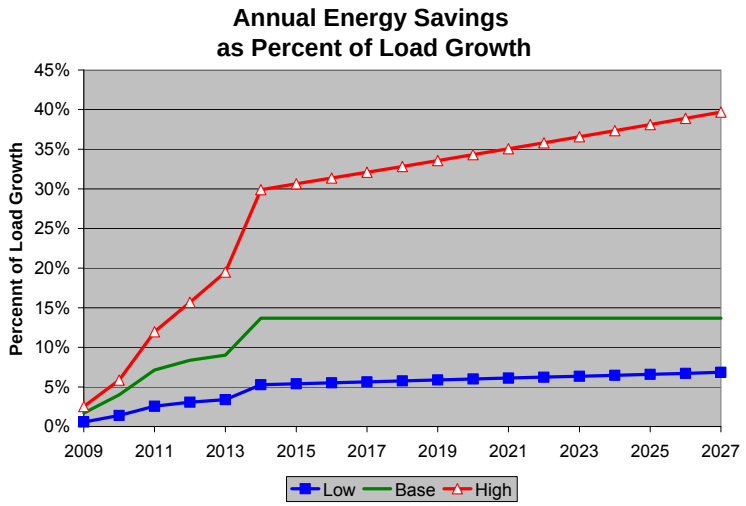
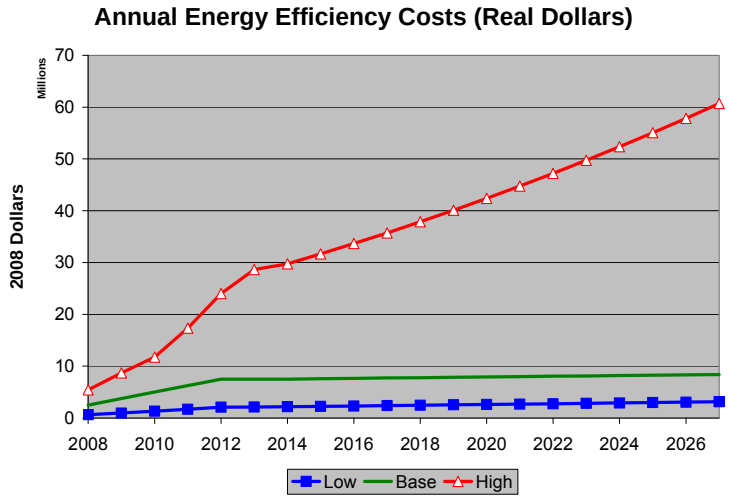


Exhibit 8.3.5-3 – Annual Energy Efficiency Costs (Real Dollars)



8.3.7 Fuel and Market Prices

In general, the prices used the assumptions from the latest Rate Track period, which extends to 2013. For fuel prices beyond this period, assumptions from the Global Energy Decision's (GED) market forecast NPPD subscribes to were generally used, with minor adjustments made to correlate to the Fuel Department's fuel forecast. The Fuel Department was also consulted in the development of the high and low fuel ranges.

The electricity market is tied very closely to the fuel market. The market forecast for the IRP model was based on GED's market forecast, and was then adjusted based on the fuel prices above. In general, the electricity market was correlated to the natural gas market during on-peak periods, coal prices during the off-peak periods, and the long-term prices were reviewed such that they would generally follow the busbar costs for new units.

Exhibit 8.3.6-1 – Coal Cost Assumptions

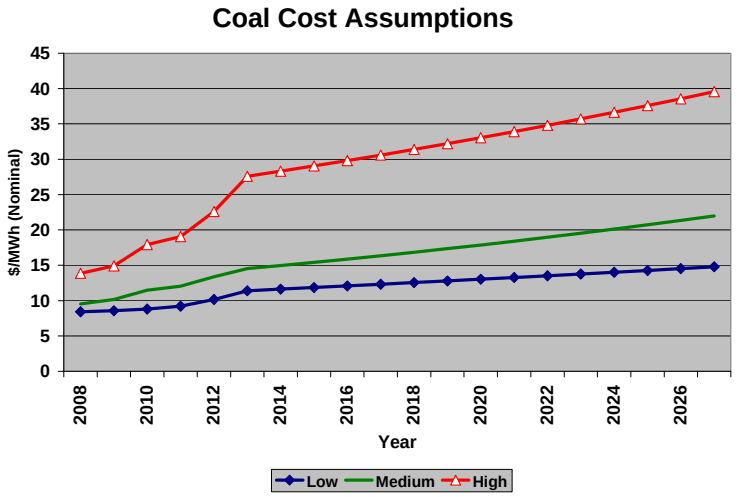


Exhibit 8.3.6-2 – Nuclear Fuel Costs

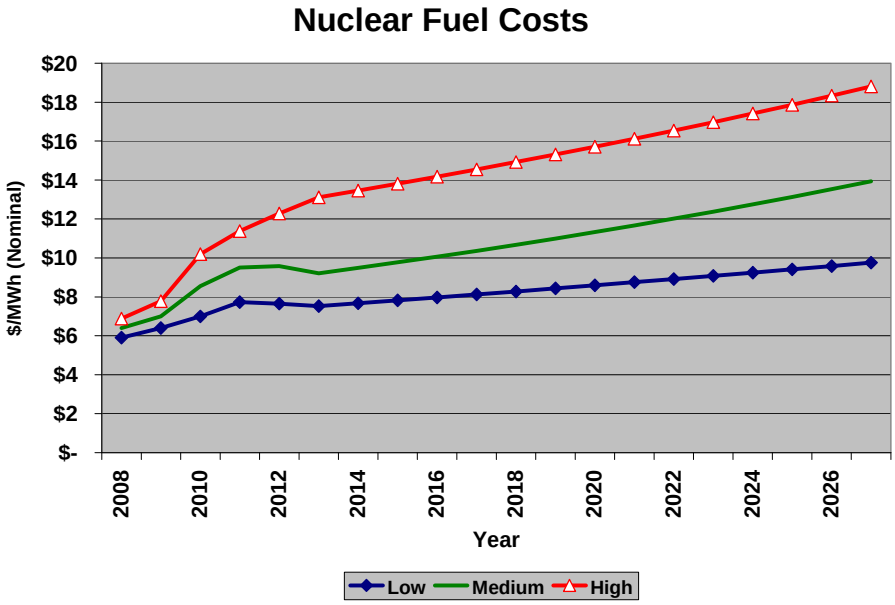
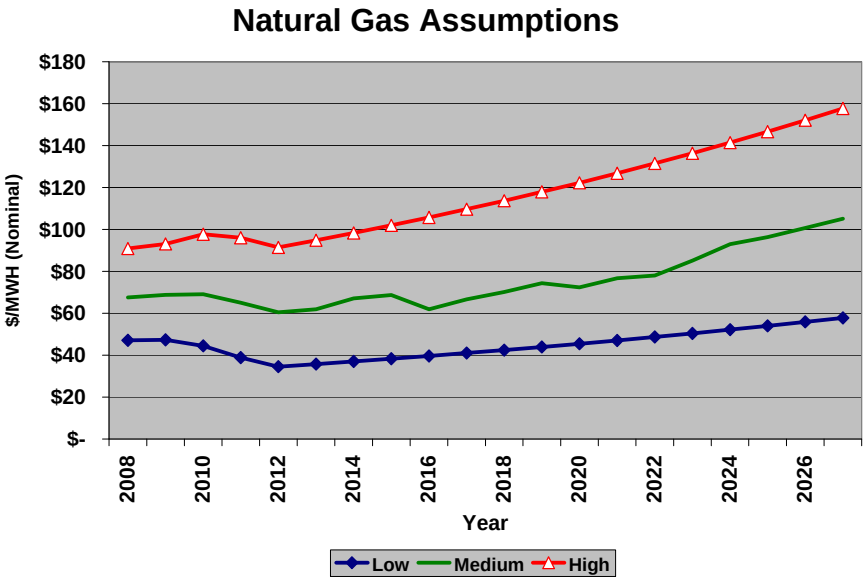


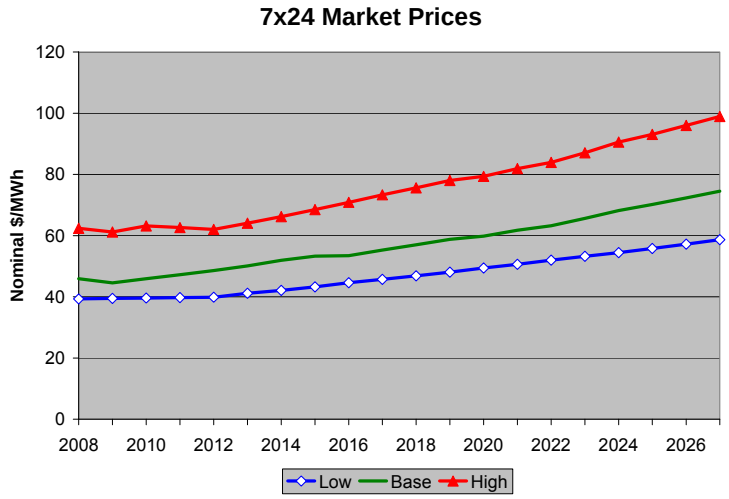
Exhibit 8.3.6-3 – Natural Gas Assumptions



The energy market prices provided in Exhibit 8.3.6-4 assume no costs due to carbon emissions. Adjustments were made to the market prices for those scenarios with carbon costs in them. These adjustments were based on the cost of carbon emissions for coal units. The incremental market price adjustment was 50-80% of the incremental cost of carbon emissions for a new coal fired plant. In addition, these values are also correlated to natural gas units since the CO_2 emission rate of a natural gas combined cycle unit is approximately 1/2 that of a new coal unit. These ranges were based on consultants' recommendations in previous studies performed within the last couple of years.

The market prices provided in Exhibit 8.3.6-4 assume a baseline price for SO_2, NO_x, and Hg allowance prices. As different emission prices are picked in the Monte Carlo runs, the market prices are adjusted based on the allowance prices used vs. the baseline prices. The adjustments ranged between 20-40% of the additional expense from a new coal unit for the higher SO_2 and Hg allowance price, to a range of 50-65% of the additional expense from a coal unit for NO_x. Again, these ranges were based on consultants' recommendations in previous studies performed within the last couple of years. It should be noted that the CO_2 market adjustment is significantly greater than the combined market adjustments for SO_2, NO_x, and Hg.

Exhibit 8.3.6-4 – 7x24 Market Prices



8.3.8 Multi-Pollutant Control (MPC) Equipment Costs

Sheldon's MPC costs were estimated based on two engineering studies. Costs from these studies were increased by 25% to account for the recent escalation in construction costs.

- Low – Costs associated with NPPD meeting air emission requirements from a system basis. As such, not all of the MPC equipment for Sheldon associated with the base or high case was included in this case.
- Base – Costs associated with NPPD meeting air emission requirements from a unit basis for SO_2, NO_x, & Hg emission control. The engineering analysis with the lower cost estimate was used for this case.
- High – Costs associated with NPPD meeting air emission requirements from a unit basis for SO_2, NO_x, & Hg emission control. The engineering analysis with the higher cost estimate was used for this case.

MPC costs for GGS were not treated as uncertainties in the IRP model. NPPD's 2007 Wholesale Rate Outlook assumptions include estimated capital costs for MPC equipment at GGS and these costs were reflected in the base revenue requirement assumptions applied to all resource plans. The GGS MPC assumptions continue to be reviewed.

8.4 Resource Plans

The resource plans utilized in the IRP model were generally grouped into one of three categories:

1) Cases where the minimal amount of energy efficiency and renewables were added,
2) Cases where a moderate amount of energy efficiency and renewables were added, and
3) Cases where an extreme amount of energy efficiency and renewables were added. The resource plans generally met the following conditions:

- The present 15% reserve margin in MAPP for summer conditions. For example, wind was assumed to be accredited at 17% of nameplate, and combustion turbines were derated from ISO conditions to the expected inlet pressures and temperatures.
- Each plan met one of the RPS scenarios except for one case (Min5) where all new wind outside of the Rate Track period was removed.
- Each plan used one of the energy efficiency cases except for one case (Min5) where all energy efficiency was removed.

Each of the initial twelve[12] resource plans is summarized in Exhibit 8.4.1. A detailed description of each plan can be found in Appendix D.

Exhibit 8.4-1 – Summary of Resource Plans for the IRP Model

IRP Expansion Plans 2008-2027
Minimal Regulation

Plan Name	Energy Efficiency *	Renewables*	Cogeneration *	Peaking	Intermediate	Baseload	1 Year Capacity Purchases
Min1 (Base)	69 MW	415 MW	110 MW	0 MW	237 MW CC 2018	60 MW-CNS Uprate 157 MW-Neb City - 2009 300 MW-New Coal - 2022, 2027	175 MW - 2008 200 MW - 2009 25 MW - 2017, 2026
Min2	69 MW	415 MW	60 MW	150 MW CT 2009	0 MW	60 MW-CNS Uprate 157 MW-Neb City - 2009 300 MW-New Coal - 2020, 2025	175 MW - 2008 50 MW - 2009 25 MW - 2019 75 MW - 2024
Min3	69 MW	415 MW	60 MW	150 MW CT 2022	237 MW CC 2025	60 MW-CNS Uprate 157 MW-Neb City - 2009 300 MW-New Coal - 2017	175 MW - 2008 200 MW - 2009 25 MW - 2010, 2016, 2023 50 MW - 2013 75 MW - 2024
Min4	69 MW	415 MW	60 MW	150 MW CT 2020	0 MW	60 MW-CNS Uprate 157 MW-Neb City - 2009 -157 MW-Reduce Fossil - 2017 300 MW-New Coal 2017 300 MW-New Coal 2022	175 MW - 2008 200 MW - 2009 25 MW - 2010, 2016, 2026 50 MW - 2013, 2019 75 MW - 2027
Min5	0 MW	115 MW	110 MW	0 MW	237 MW CC 2017	60 MW-CNS Uprate 157 MW-Neb City - 2009 300 MW-New Coal 2021, 2025	175 MW - 2008 200 MW - 2009 25 MW - 2013, 2016, 2024

* Total in 2027

[12] Initially twelve representative resource plans were developed for detailed analysis in the IRP model. As a result of comments received through the public input process regarding the draft 2008 IRP report, NPPD developed four additional resource plans to further study alternative Energy Efficiency program assumptions around the Mod 1 plan. The results from these additional plans are discussed in section 9.6.

IRP Expansion Plans 2008-2027
Moderate Regulation

Plan Name	Energy Efficiency *	Renewables*	Cogeneration *	Peaking	Intermediate	Baseload	1 Year Capacity Purchases
Mod1 (Base)	161 MW	665 MW	160 MW (10 MW Renewable)	0 MW	237 MW CC 2021	60 MW-CNS Uprate 157 MW-Neb City - 2009 300 MW-New Coal- 2022 -157 MW-Reduce Fossil-2022	175 MW - 2008 200 MW - 2009 50 MW - 2020, 2027
Mod2	161 MW	665 MW	60 MW	150 MW New CT 2010 -52 MW Reduce CT 2010	237 MW CC 2021	60 MW-CNS Uprate 157 MW-Neb City - 2009 300 MW-New Coal - 2022 -157 MW-Reduce Fossil - 2022	175 MW - 2008 200 MW - 2009 50 MW - 2020, 2027
Mod3	161 MW	665 MW	110 MW (10 MW Renewable)	0 MW	334 MW Pumped Storage 2019	60 MW-CNS Uprate 157 MW-Neb City - 2009 300 MW-New Coal - 2022 -157 MW-Reduce Fossil - 2022	175 MW - 2008 200 MW - 2009

* Total in 2027

IRP Expansion Plans 2008-2027
Extreme Regulation

Plan Name	Energy Efficiency *	Renewables*	Cogeneration *	Peaking	Intermediate	Baseload	1 Year Capacity Purchases
Ext1 (Base)	383 MW	1615 MW	210 MW (20MW Renewables)	0 MW	0 MW	60 MW-CNS Uprate 157 MW-Neb City - 2009 -157 MW-Reduce Fossil-2015 400 MW-New Nuclear - 2022	175 MW - 2008 200 MW - 2009
Ext2	383 MW	1615 MW	150 MW (20MW Renewables)	0 MW	668 MW Pumped Storage 2019	60 MW-CNS Uprate 157 MW-Neb City - 2009 -157 MW-Reduce Fossil-2015	175 MW - 2008 200 MW - 2009
Ext3	383 MW	1615 MW	150 MW (20MW Renewables)	150 MW - 2009, 2022, 2027 - 52 MW - Reduce CT - 2010	0 MW	60 MW-CNS Uprate 157 MW-Neb City - 2009 -157 MW-Reduce Fossil-2015	175 MW - 2008 50 MW - 2009
Ext4	383 MW	1365 MW (100MW Solar)	150 MW (20MW Renewables)	0 MW	0 MW	60 MW-CNS Uprate 157 MW-Neb City - 2009 -157 MW-Reduce Fossil-2015 75 MW Biomass - 2019 300 MW-New Coal (CCS)-2022	175 MW - 2008 200 MW - 2009

* Total in 2027

9. RESULTS

Since twelve different resource plans were modeled over a 20-year period, a simple, but accurate way of representing the results is required. As stated in Section 8.1, standard NPPD and utility practice is to use the net present value method to evaluate the different wholesale revenue requirements of each plan. A discount rate of 5.25% was used in the analysis.

This section will first provide the overall results of the IRP model using "flying bar" graphs. Since the IRP model uses Monte Carlo simulations to quantify uncertainty, there is an uncertainty band for the resulting values. Flying bars are a graphical representation of the range of potential outcomes.

Since the flying bars typically only show the results from the 10th percentile to the 90th percentile, "Tail Value" curves were developed to identify the risks above the 90th percentile as it relates to the expected value. These curves help quantify the outlier risks for each resource plan.

Next, the major drivers of uncertainty will be reviewed by the use of tornado diagrams. "Tornado" diagrams allow for a visual representation of which variables create the most uncertainty in the model results. The tornado diagrams will show that CO_2 is the greatest uncertainty modeled. The next section will then show how the lowest cost resource plans compare to one another based on the different CO_2 scenarios.

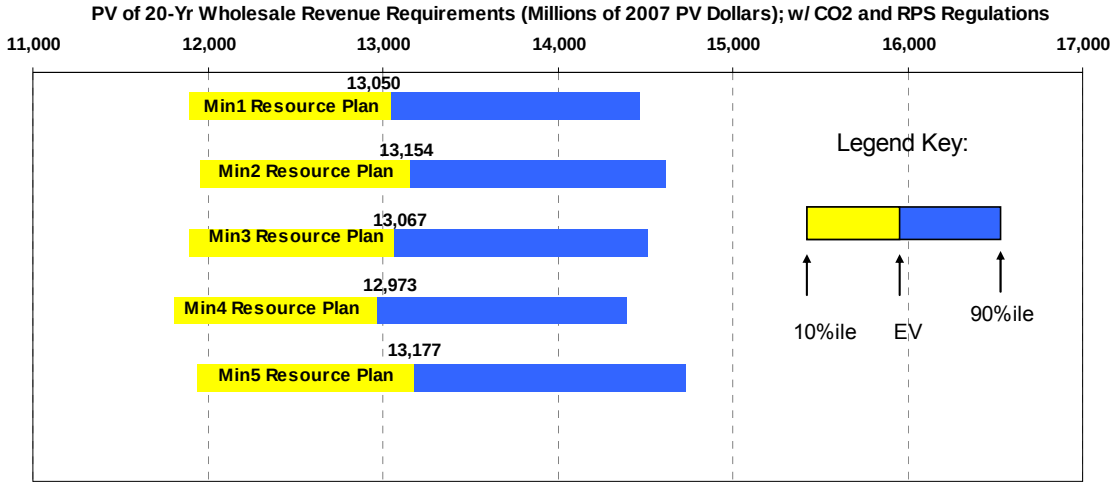
The report will then look at the lowest cost resource plans in the latter part of the study periods, and will indicate which of these plans provide NPPD with the best position to move forward after 2027. After that, results from an additional analysis of energy efficiency program assumptions will be discussed. The last section will provide a summary of the above.

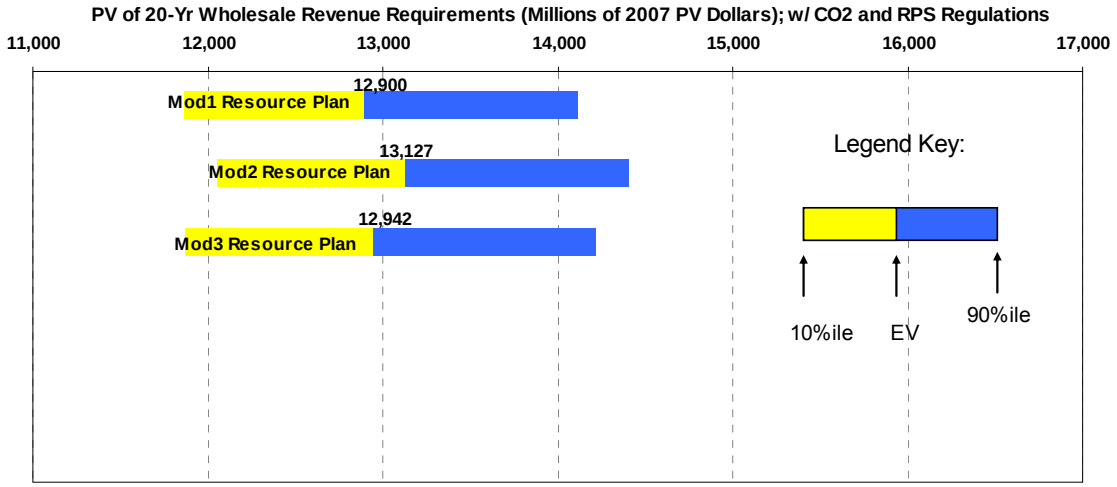
9.1 Flying Bar Results

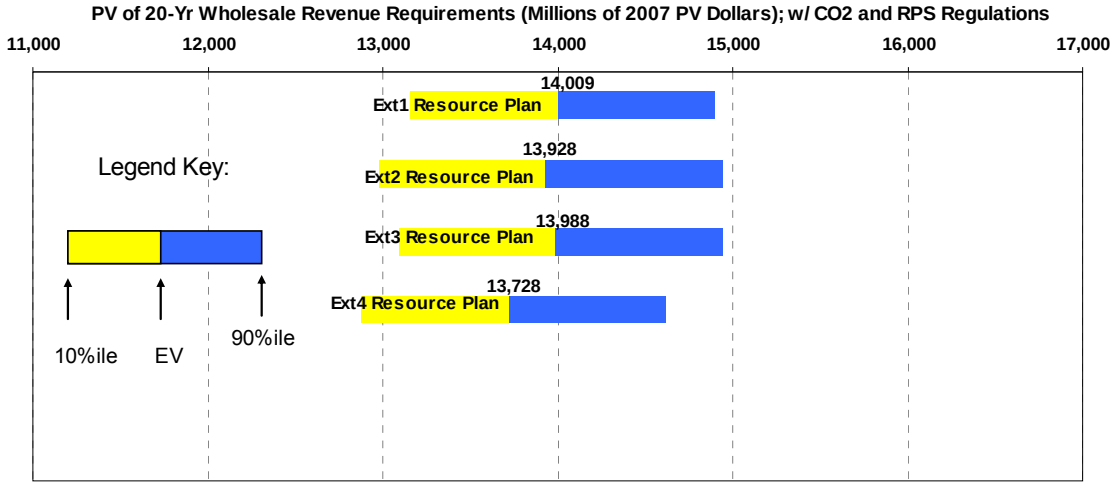
The IRP model ran 5,000 Monte Carlo simulations for each expansion plan. The NPV value of wholesale revenue requirements was calculated for each simulation. The average of these values is described as the expected value, or mean. The 500th lowest cost simulation equates to the 10th percentile value, and the 500th highest cost simulation equates to the 90th percentile value.

The results are shown in Exhibit 9.1-1. The exhibit breaks out the resource plans between the minimal, moderate, and extreme plans. In review, the minimal resource plans were developed to generally meet the low RPS scenario requirements with the exception of the Min5 plan, which did not include any energy efficiency programs and only included 115 MW of wind that was assumed in Rate Track. The moderate resource plans were developed to generally meet the base RPS scenario requirements, and the extreme resource plans were developed to generally meet the high RPS scenario requirements. In general, the results show that the moderate resource plans and minimal resource plans were relatively close to one another in cost, with the moderate plans typically having slightly lower expected values and smaller uncertainty ranges. The extreme plans had the smallest range of uncertainty, but this reduction of risk carried with it a higher expected value.

Exhibit 9.1-1 - IRP Model Results – Flying Bars







The four lowest cost resource plans based on the expected value of the NPV costs of wholesale revenue requirements are:

- Mod1 Resource Plan – $12.90 billion
- Mod3 Resource Plan – $12.94 billion
- Min4 Resource Plan – $12.97 billion
- Min1 Resource Plan – $13.05 billion

Details of all the resource plans can be found in Appendix D, and a comparison between the four lowest cost resource plans is provided in Exhibit 9.1-2.

Exhibit 9.1-2 – Resource Plans by Year

Resource Plans by Year

Notes:
xxx = differences from Mod1
1 yr purchases not shown
Wind MW in nameplate rating

	Mod1	Mod3	Min4	Min1
2008	11 CNS	11 CNS	11 CNS	11 CNS
2009	50 Cogen 157 NC2	**40** Cogen 157 NC2	**30** Cogen 157 NC2	50 Cogen 157 NC2
2010	55 Cogen 115 Wind	**45** Cogen 115 Wind	**30** Cogen 115 Wind	**50** Cogen 115 Wind
2011	10 CNS 35 Cogen	10 CNS **25** Cogen	10 CNS **0** Cogen	10 CNS **10** Cogen
2012	39 CNS 20 Cogen	39 CNS **0** Cogen	39 CNS **0** Cogen	39 CNS **0** Cogen
2013				
2014	50 Wind	50 Wind	50 Wind	50 Wind
2015	50 Wind	50 Wind	**0** Wind	**0** Wind
2016	50 Wind	50 Wind	50 Wind	50 Wind
2017	50 Wind	50 Wind	**300 Coal** **-157 Coal** **0** Wind	**0** Wind
2018	50 Wind	50 Wind	50 Wind	**237 CC** 50 Wind
2019	50 Wind	**334 PS** 50 Wind	**0** Wind	**0** Wind
2020	50 Wind	50 Wind	**150 CT** **0** Wind	**0** Wind
2021	237 CC	**0 CC**	**0 CC**	**0 CC**
2022	300 Coal -157 Coal	300 Coal -157 Coal	300 Coal **50 Wind**	300 Coal **50 Wind**
2023	50 Wind	50 Wind	**0** Wind	**0** Wind
2024	50 Wind	50 Wind	**0** Wind	**0** Wind
2025	0 Wind	0 Wind	**50** Wind	**50** Wind
2026	50 Wind	50 Wind	**0** Wind	**0** Wind
2027	50 Wind	50 Wind	50 Wind	**300 Coal** 50 Wind
Egy Eff by 2027	161	161	69	69
Wind by 2027	665	665	415	415
Cogen by 2027	160	110	60	110
Coal by 2027	300	300	600	757

(note: Coal by 2027 does not include GGS)

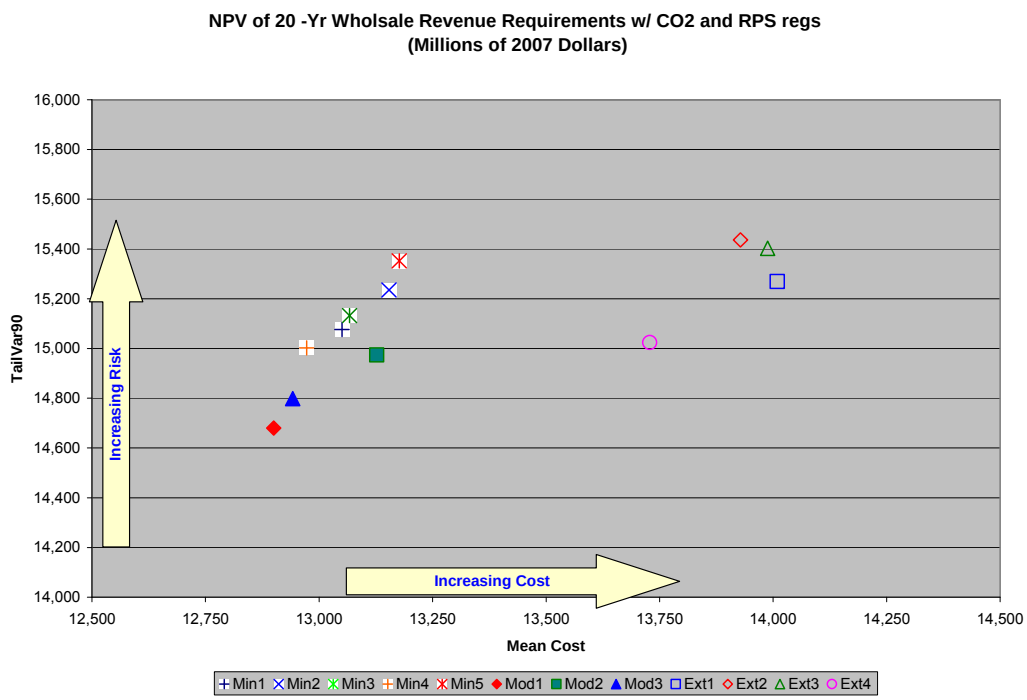
9.2 Tail Value Curves

The flying bars typically only provide a range between the 10th and 90th percentile values, so it does not provide details for the outcomes beyond the 90th percentile. The costs for these outcomes can be significantly higher than the 90th percentile value, which results in a long "tail". Although these risks are not as likely to happen, not understanding the potential outcomes of these risks may result in a faulty decision process.

The Northwest Power and Conservation Council used tail value curves to compare the costs of these "tail" values to the expected value in their most recent regional plan. This curve basically graphs the average of the outcomes greater than the 90th percentile on the y-axis (risk) and the average, or expected values of all outcomes on the x-axis. Resource scenarios that are in the bottom left quadrant have lower expected costs and risks to those in the upper right quadrant. A low cost plan does not necessarily have to be the low risk plan too. This graph helps to understand the potential tradeoffs between costs and risks.

Exhibit 9.2-1 is the tail curve graph when including the CO_2 and RPS scenarios. The Mod1 and Mod3 resource plans not only have the lowest cost, they also have the lowest relative risk. The 3rd and 4th lowest cost plans, Min1 and Min4, also have relatively low risks when compared to the other resource plans.

Exhibit 9.2-1 – NPV of 20-Yr Wholesale Revenue Requirements w/CO2 & RPS Regs



9.3 Tornado Diagrams

Tornado diagrams provide an easy way to understand which variables can cause the greatest variation in the results. Tornado diagrams are created by simply holding all variables constant (typically at its base value), then allowing one of the inputs to vary and noting the change in the output, or NPV values. After this is completed for all of the inputs, the results are provided in a graph, listing the inputs with the greatest variation in the results at the top, thus creating a "tornado".

The following four exhibits provide the tornado diagrams for the four lowest expected value resource plans. For each of these plans, the top four variables remained the same: 1) CO_2 cost, 2) Load Forecast, 3) Coal Fuel Cost, and 4) Non-firm Market Price. Roughly half of the variation can be explained by the CO_2 cost. Roughly 90% of the variation can be explained by the combination of the top four (4) variables. In the four expansion plans, the RPS requirement varies between 5th largest variable to 7th largest. This is one indication that RPS requirements, though significant, are not as influential on cost as are these other variables.

Since NPPD owns a significant amount of coal, and the cost of CO_2 in the high case was greater than the present busbar cost of our generating units, it is easy to understand why the CO_2 cost was the most significant variable. It is also obvious that the wholesale revenue requirements will increase as the cost of CO_2 increase.

A higher load forecast also results in higher wholesale revenue requirements. As load increases, the incremental load will need to be served by a combination of NPPD's higher priced units, non-firm purchases, or a reduction in non-firm sales. Since the energy portion of NPPD's wholesale rates is less than the market price, a reduction of non-firm sales will increase the wholesale revenue requirements of the wholesale customers.

Since NPPD generates a significant amount of electricity from coal, variations in coal prices should have a major impact on wholesale revenue requirements. Also note that a higher coal price for NPPD does not typically impact the market, thus there is no additional revenues to offset the higher coal prices. Finally, since NPPD is typically a net seller into the non-firm market, an increase in the non-firm market price provides more non-firm revenue than non-firm purchase costs, resulting in lower wholesale revenue requirements.

Exhibit 9.3-1 – PV of Whol Rev Req-Case = w/CO_2, w/RPS; Moderate Regulation Scenario – Mod1 (Base)

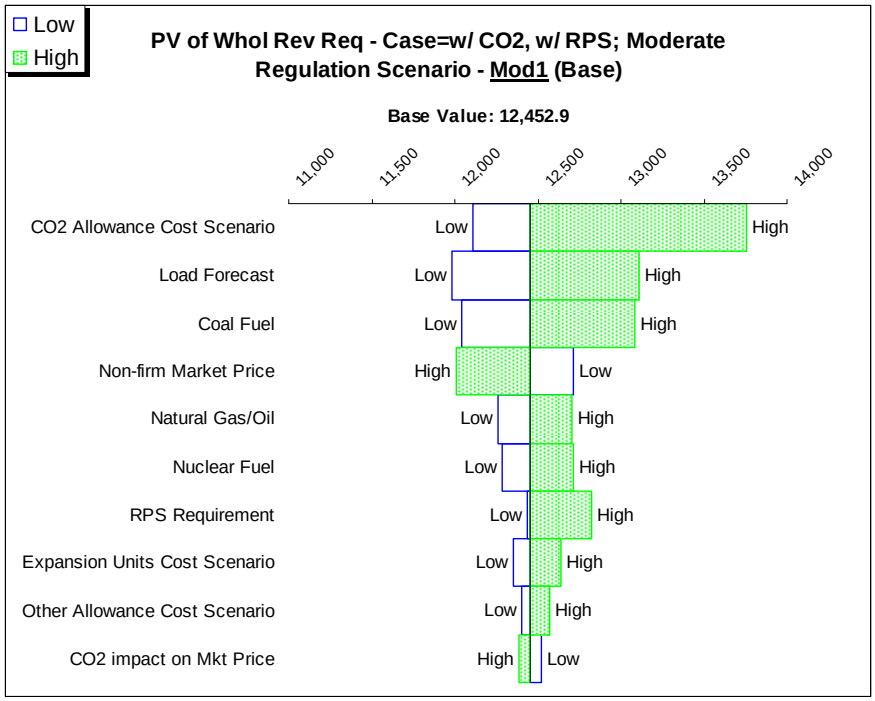


Exhibit 9.3-2 - PV of Whol Rev Req-Case = w/CO_2, w/RPS; Moderate Regulation Scenario – Mod3

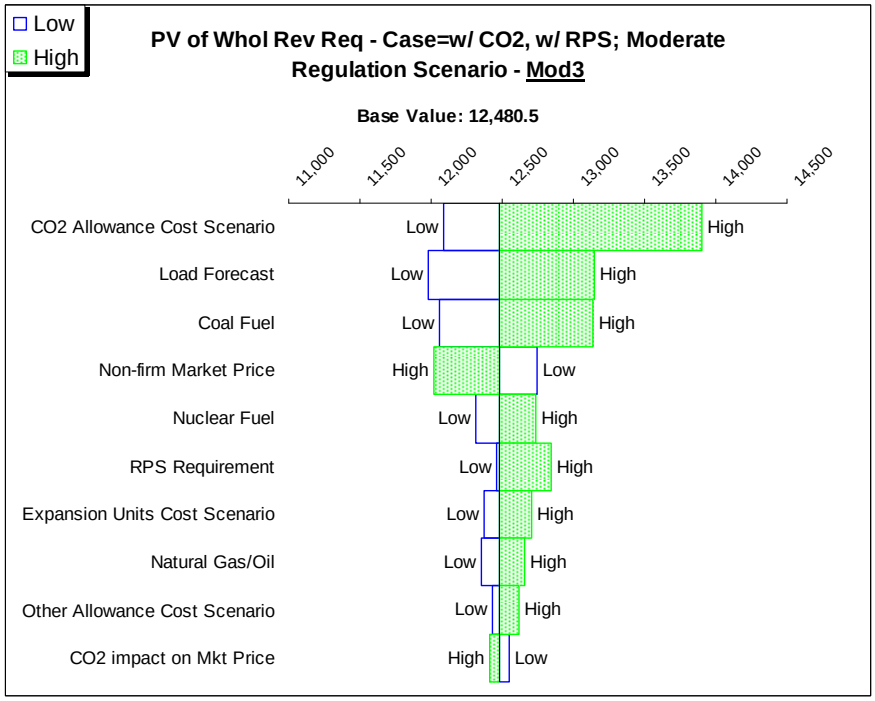


Exhibit 9.3-3 – PV of Whol Rev Req-Case=w/CO_2, w/RPS; Minimal Regulation Scenario – Min4

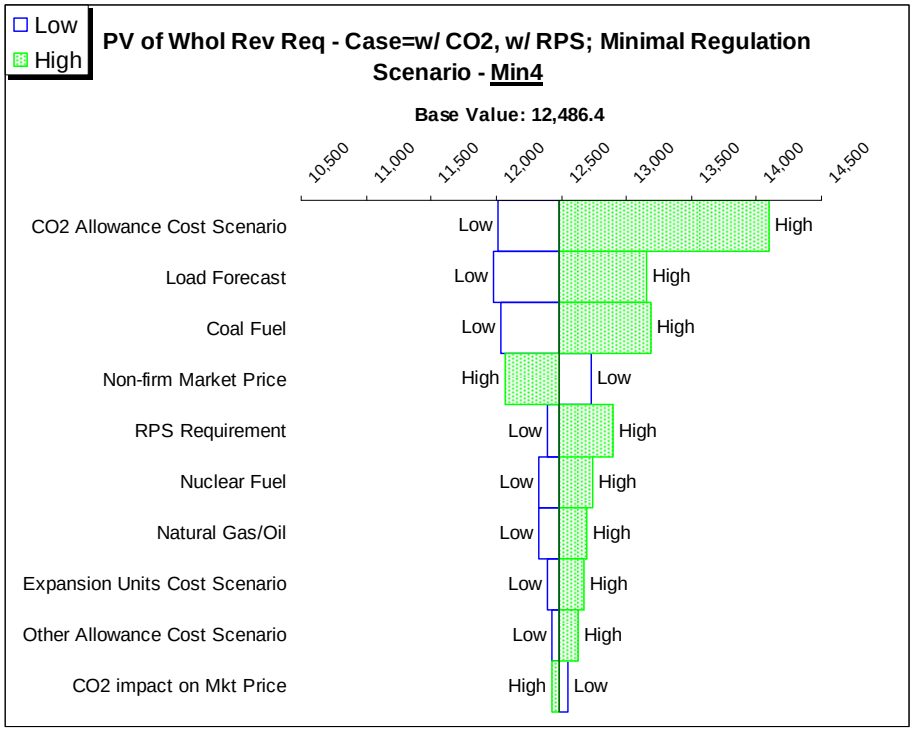
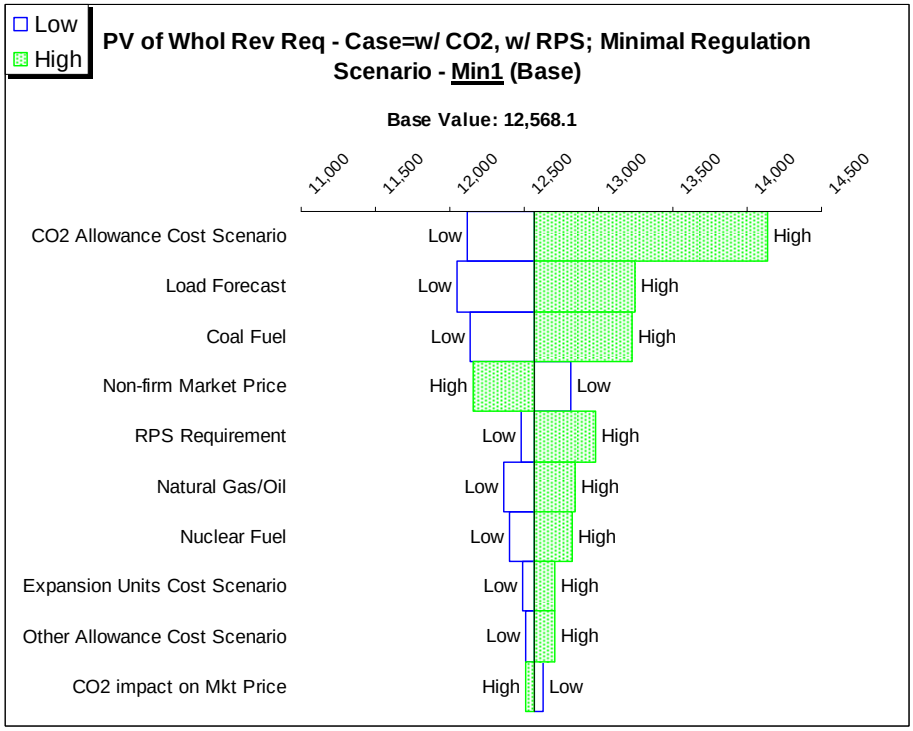


Exhibit 9.3-4 - PV of Whol Rev Req-Case=w/CO_2, w/RPS; Minimal Regulation Scenario – Min1 (Base)



9.4 CO_2 Cost / RPS Scenarios

Description of approach for examining special CO_2/RPS scenarios

As noted in Section 8.2.2, increasing RPS requirements were positively, but not fully, correlated with increasing CO_2 cost. This partial correlation was used for the bulk of the study, including the weighted model results discussed in this section. Some runs were also made for a No CO_2 cost / No RPS scenario for informational purposes, although that scenario was not weighted in with the other scenarios for weighted or overall expected value results. Note that "No RPS" terminology means that no RPS law is applicable to Nebraska; although a low range of REC prices still exists, as is the case today, and is modeled that way.

In this Section 9.4, some directly linked results with complete positive correlation between CO_2 cost and RPS requirement are presented; i.e., both at no, both at low, both at base and both at high, as shown in Exhibit 9.4-1.

CO_2 cost is by far the greatest uncertainty in the IRP model. It is important to consider its effect carefully. This section takes another approach to understand the impact of CO_2 cost (and RPS requirement) on the various resource plans. Since there will only be one CO_2/RPS future, a robust plan should fare well under all such scenarios. Please note that each CO_2/RPS scenario should not be given the same weight. The base CO_2/RPS scenario was deemed the most likely in the IRP model. Exhibit 9.4-1 provides a comparison of the top four plans for the three CO_2/RPS scenarios in the IRP model, along with a scenario where no CO_2/RPS is included in the future. For informational purposes, Exhibit 9.4-1 also includes the Min5 plan which was similar to the Min1 plan but excluded any energy efficiency benefits and wind generation development beyond 2011. The exhibit also includes the overall IRP results, which combines the three CO_2/RPS scenarios (i.e. excluding the No CO_2 / No RPS scenario). Three pieces of information are provided: 1) Expected value of the NPV of wholesale revenue requirements of the resource plan for each CO_2/RPS scenario, 2) Relative ranking of the resource plan versus all twelve plans, and 3) How much higher the resource plan's expected value is versus the expected value of the lowest cost plan for that particular CO_2/RPS scenario.

Robustness of the top four plans and relative comparisons

A review of Exhibit 9.4-1 indicates that the top four plans are relatively robust since their NPV revenue requirement costs are close to the top plan for each scenario. The "moderate" plans tend to perform better than the "minimal" plans with base or high CO_2/RPS scenarios. Oppositely, the "minimal" plans tend to perform better than the "moderate" plans with low or no CO_2/RPS scenarios. This was the expected result.

Exhibit 9.4-1 - Results of Various CO_2 Cost / RPS* Scenarios

Exhibit 9.4-1 - Results of Various CO_2 Cost / RPS Scenarios*

		Mod1	Mod3	Min4	Min1	Min5
No CO_2 Cost /No RPS	EV Revenue Required	12,068	12,008	11,831	11,945	11,872
	Ranking	7	6	1	4	2
	Percent above Top Plan	2.00%	1.50%	0.00%	0.96%	0.35%
Low CO_2 Cost /Low RPS Scenario	EV Revenue Required	12,210	12,188	12,052	12,153	12,164
	Ranking	6	5	1	3	4
	Percent above Top Plan	1.31%	1.13%	0.00%	0.84%	0.93%
Base CO_2 Cost /Base RPS Scenario	EV Revenue Required	12,586	12,613	12,622	12,705	12,805
	Ranking	1	2	3	4	7
	Percent above Top Plan	0.00%	0.21%	0.29%	0.95%	1.74%
High CO_2 Cost /High RPS Scenario	EV Revenue Required	14,277	14,415	14,655	14,699	14,994
	Ranking	1	3	5	7	12
	Percent above Top Plan	0.00%	0.97%	2.65%	2.96%	5.02%
Weighted IRP Model Results	EV Revenue Required	12,900	12,942	12,973	13,050	13,177
	Ranking	1	2	3	4	8
	Percent above Top Plan	0.00%	0.33%	0.57%	1.16%	2.15%

* In this table, "RPS" refers to both RPS requirement and REC price such that, e.g., "Base RPS" means Base RPS requirement and Base REC price, except that "No RPS" means no RPS requirement for Nebraska but the REC price varies over a range of low values thereby representing the renewable conditions today in Nebraska. Also EV = Expected Value.

Results for the Min5 plan having no energy efficiency benefits and no wind generation development beyond 2011

Exhibit 9.4-1 shows the results for the Min5 plan, which includes no energy efficiency benefits and whereby no future wind generation development beyond 2011 is permitted, as a comparison to the Min1 plan (the Min5 plan eliminates 300 MW of wind generation facilities from Min1 and removes the 69MW of energy efficiency programs from Min1). This Min5 plan (without wind generation development and without energy efficiency) is never the least cost plan, including in the No CO_2 / No RPS scenario. Further, the Min5 plan is the highest cost plan of the five plans shown in Exhibit 9.4-1 whenever the CO_2/RPS variable is base or higher.

Rough Estimate of the Cost Effect from CO_2 Regulation

As noted in the scenario cases of Exhibit 9.4-1, CO_2 and RPS are varied together and so the results have the cost effects of both variables intertwined. However from the tornado diagram results of Section 9.3 it is known that by far the larger of the two variables is the CO_2 cost.

As mentioned, the No CO_2 Cost / No RPS scenario is included in Exhibit 9.4-1 for information although it was not weighted into the overall IRP model results. What the No CO_2 / No RPS scenario does is provide a means to make a rough estimate of the expected cost of these future regulations. Note that the SO_2, NO_x, and Hg emission costs, as well as the multi-pollutant control equipment and operating costs are not zeroed in the No CO_2 / No RPS scenario.

In order to make a rough estimate of the expected cost of future regulation on CO_2 emissions, the best plan (Min4) results for the No CO_2 / No RPS scenario are compared to the best plan (Mod1) results for the weighted IRP model results. Because the level of CO_2 and RPS regulations is uncertain the weighted results are used for the regulation case. From Exhibit 9.4-1 this regulation-related cost increase is found to be from $11.831 billion to $12.900 billion, or an increase of 9% in these net present value costs over the full 20-year period. Examining the annual nominal revenue requirement differences shows that this higher cost is 0.2% initially and 27% at the end of the 20-year period. The rate impact at the retail level would be expected to be somewhat less.

Of course, the impact from a high cost CO_2 regulation would be greater. From Exhibit 9.4-1 this increase from high CO_2 cost is found to be from $11.831 billion to $14.277 billion, or an increase of 21% in these net present value costs over the full 20-year period. Examining the annual nominal revenue requirement differences shows that this higher cost is 0.1% initially and 60% at the end of the 20-year period. The rate impact at the retail level would be expected to be somewhat less.

Examination of the Extent of Emission Allowance Purchases Needed

Based on the recommendation of the IRP Climate Change Strategy Team the IRP model assumes that NPPD will be able to buy CO_2 allowances or offsets for its emissions that exceed the free allowances allocation. This becomes a critical assumption, especially for the "minimal" resource plans, since it will be purchasing a significant amount of CO_2 allowances or offsets in the high CO_2 cost scenario.

The next three exhibits show the amount of CO_2 emissions versus free allowances. The allowance and emissions values in the exhibits are the average values for all scenarios/simulations given in metric tons, whereas the historical emission dates presented in 8.2.2 and 4.2 are given in short tons (1 metric ton approximately equal 1.1 short tons). Thus, CO_2 emissions for each resource plan in the low CO_2 cost scenario will look relatively better than what is shown on the exhibits and relatively worse than the exhibits in the high CO_2 cost scenario. The average amount of free CO_2 allowances is approximately 5 million metric tons in 2027. This will range in 2027 from approximately 3 million metric tons for the high CO_2 cost scenario to just over 7 million metric tons in the low CO_2 cost scenario. **Exhibit 8.2.2-2** shows amount of allowances assumed for each CO_2 cost scenario.

Exhibit 9.4-2 shows the lowest cost minimal plan, Exhibit 9.4-3 shows the lowest cost moderate plan, and Exhibit 9.4-4 shows the lowest cost extreme plan. The IRP is assuming that NPPD can purchase its way into compliance with CO_2 regulations. If this assumption does not prove correct over time NPPD will incur significant costs to reach compliance as seen from the exhibits below. The extreme plan does not rely as much on the ability to buy offsets and allowances to comply with CO_2 regulations as the other plans.

Reinforced by general feedback from the wholesale customers and the public, NPPD has included the further examination of the risks associated with this assumption of "unlimited" access to allowance purchases as a key part of the Action Plan as noted in Section 10.7.

Exhibit 9.4-2 – Annual NPPD CO_2 Emissions* - Min4 Resource Plan

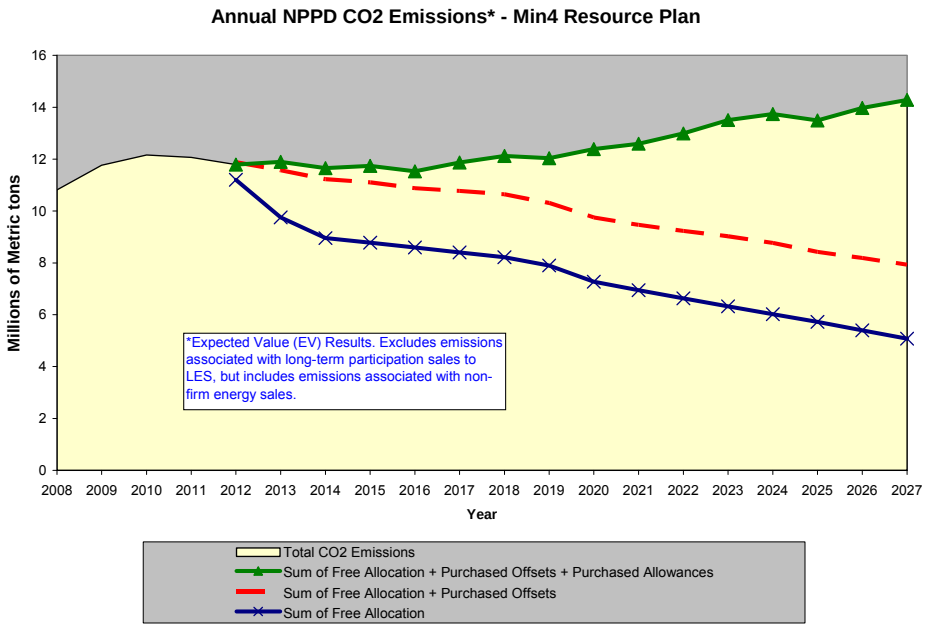


Exhibit 9.4-3 – Annual NPPD CO_2 Emissions* - Mod1 (Base) Resource Plan

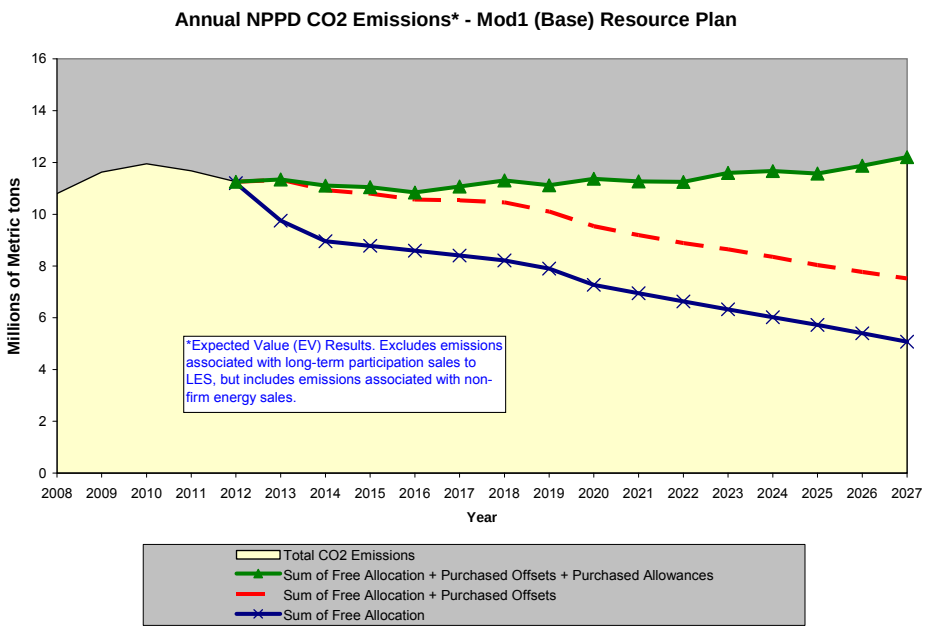
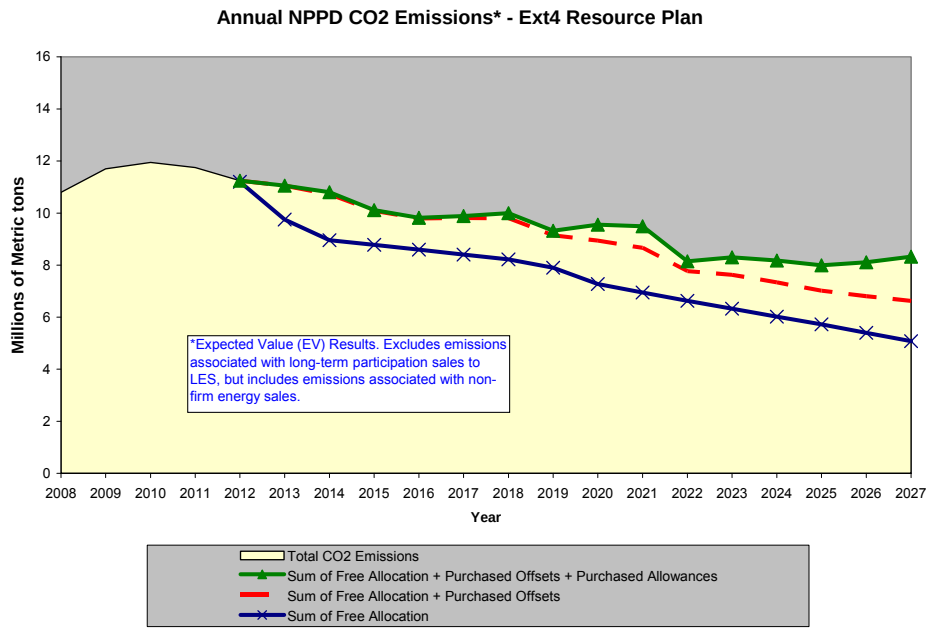


Exhibit 9.4-4 – Annual NPPD CO_2 Emissions* - Ext 4 Resource Plan



9.5 End of Study Period Results

In evaluating a range of alternative resource plans, such as those considered in this IRP, it is quite possible that there will be significant differences in the total installed capacity between different plans in any given year. The IRP model attempts to account for these differences in a couple of different ways. First, it is assumed that a viable market for capacity will continue to exist in the future. In the IRP model, it is further assumed that NPPD would be willing to sell available surplus capacity, above the severe weather Reserve Capacity Obligation (RCO), on a year-by-year basis and that this capacity has some value. These regulatory capacity sales are priced at 80% of the estimated price to purchase regulatory capacity from the market (i.e., 0.8 x $18/kW-yr in 2007 and escalating at 2.5% annually, thereafter).

Similarly, it is assumed that an energy market will also continue to exist in the future. The model assumes that as additional capacity is installed (especially baseload and non-dispatchable resources such as Wind), non-firm energy sales will increase[13]. The revenue resulting from these capacity and energy sales, although small compared to the fixed costs of a new resource[14], do serve to offset some of the impacts of varying capacity levels between the plans.

End Effects occur when the costs of resources installed near the end of the plan extend beyond the study period and are therefore not fully accounted for in the calculation of revenue

[13] A more detailed description of how non-firm energy sales are represented in the IRP model can be found in Appendix F.

[14] Please note that only the debt service costs for the years in the study period were included when calculating revenue requirements. For example, if a new unit became operational in 2027, only one year of debt service was included in the calculations. Debt service for 2028 and beyond was not included. Also, the results in 2027 were heavily discounted in the NPV results.

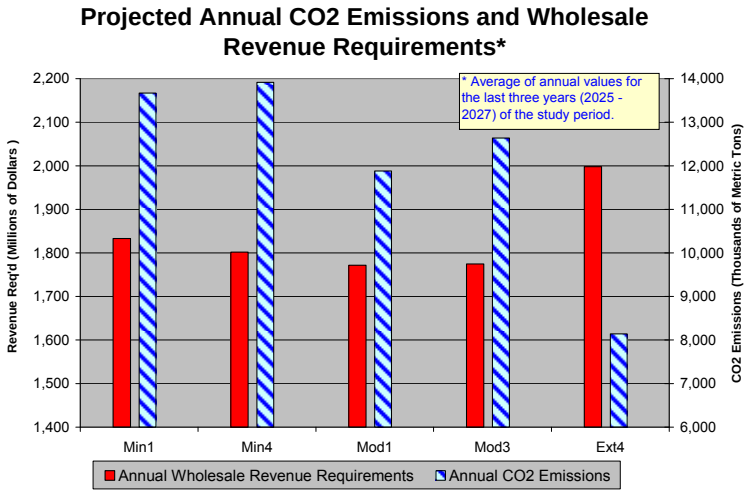
requirements for the plan. Current results do not include any end effects adjustments, although such calculations could be considered as part of future model enhancements. NPPD has chosen a medium length study period of 20 years, which attempts to strike a reasonable balance between capital intensive/low energy cost resource alternatives (e.g., coal, nuclear) and lower capital/higher energy cost alternatives (e.g., CT, CC), at least for the first few resource decisions (which is the focus of the study).

To help gauge how the different resource plans position NPPD after the study period (2027), the averages of the last three (3) years of nominal revenue requirement dollars and CO_2 emissions are shown below. The wholesale revenue requirements are the expected or mean value of the different CO_2 scenarios used in the IRP model. The CO_2 emissions are based on NPPD owned units, minus LES's share, plus NPPD's share of Nebraska City 2. As defined, any CO_2 emissions from non-firm sales are included and CO_2 emissions from all purchases, except Nebraska City 2, are excluded. The four lowest cost resource plans are shown, along with the lowest cost extreme plan. The Ext4 plan was included to highlight the differences in CO_2 emissions between the plans.

The wholesale revenue requirements for Mod1 and Mod3 are basically identical, and Min1 and Min4 are approximately 3.5% and 1.7% higher than Mod1, respectively. The Ext4 resource plan wholesale revenue requirements are almost 13% higher than Mod1.

There is a greater variation when it comes to CO_2 emissions. Min1 CO_2 emissions are 15% higher, Min4 is 17% higher, and Mod3 is 6% higher than Mod1. The Ext4 CO_2 emissions are approximately 30% below that of Mod1. For comparison purposes, NPPD owned units, excluding LES's share, emitted approximately 10.9 million metric tons of CO_2 in 2005. Only the Ext4 case shown in Exhibit 9.5-1 has fewer CO_2 emissions in these years than the 2005 actual data. No CO_2 records were kept in 1990, but our Environmental Department has estimated that NPPD owned units emitted approximately 6.5 million metric tons in 1990, excluding LES's share indicating that even Ext4 would not satisfy a 1990 emission cap.

Exhibit 9.5-1 – Projected Annual CO2 Emissions & Wholesale Revenue Requirements*



9.6 Analysis of Additional Energy Efficiency Cases

As described in Section 7.3, energy efficiency programs can provide a cost effective alternative to building additional supply-side resources. Looking at the results presented earlier portions of section 9, the plans that performed best, included energy efficiency savings of between 7% and 14% of NPPD's annual load growth by 2027 (Low and Base assumptions, respectively).

Once of the action items included in the draft IRP report recommended that NPPD implement energy efficiency programs at a level that generally corresponds with the Low assumptions in the analysis. A number of comments received by NPPD on the draft IRP, as part of the public input process, encouraged the District to implement energy efficiency programs at higher levels than those reflected in the Low assumptions.

In response to this public feedback, four additional resource plans were developed around the Mod1[15] plan to better examine the economics of varying levels of energy efficiency investment. A comparison between these four additional resource plans and the Mod1 plan is provided in Exhibit 9.6-1. The Mod4 and Mod5 plans include energy efficiency reductions based on the High study assumptions, as opposed to Base assumptions for Mod1. The Mod6 plan assumes no additional energy efficiency reductions, while the Mod7 plan uses Low energy efficiency assumptions.

[15] The Mod1 plan was selected as the base case for this additional analysis as it is one of the top four resource plans, based on the analysis results presented in sections 9.1, 9.2, 9.4, and 9.5.

Exhibit 9.6-1 Additional Energy Efficiency Resource Plans by Year

Resource Plans by Year

Notes:
xxx = differences from Mod1
1 yr purchases not shown
Wind MW in nameplate rating

	Mod1	Mod4	Mod5	Mod6	Mod7
2008	11 CNS	11 CNS	11 CNS	11 CNS	11 CNS
2009	50 Cogen 157 NC2	50 Cogen 157 NC2	50 Cogen 157 NC2	50 Cogen 157 NC2	50 Cogen 157 NC2
2010	55 Cogen 115 Wind	55 Cogen 115 Wind	55 Cogen 115 Wind	55 Cogen 115 Wind	55 Cogen 115 Wind
2011	10 CNS 35 Cogen	10 CNS 35 Cogen	10 CNS 35 Cogen	10 CNS 35 Cogen	10 CNS 35 Cogen
2012	39 CNS 20 Cogen	39 CNS 20 Cogen	39 CNS 20 Cogen	39 CNS 20 Cogen	39 CNS 20 Cogen
2013				**50** Wind	**50** Wind
2014	50 Wind	50 Wind	50 Wind	**0** Wind	**0** Wind
2015	50 Wind	50 Wind	50 Wind	50 Wind	50 Wind
2016	50 Wind	50 Wind	50 Wind	50 Wind	50 Wind
2017	50 Wind	50 Wind	50 Wind	50 Wind	50 Wind
2018	50 Wind	50 Wind	50 Wind	50 Wind	50 Wind
2019	50 Wind	50 Wind	50 Wind	50 Wind	50 Wind
2020	50 Wind	**0** Wind	**0** Wind	**237** CC 50 Wind	**237** CC 50 Wind
2021	237 CC	**0** CC **50** Wind	**0** CC **50** Wind	**0** CC **50** Wind	**0** CC **50** Wind
2022	300 Coal -157 Coal	**0** Coal -157 Coal **237** CC **50** Wind	**0** Coal **237** CC **50** Wind	300 Coal -157 Coal	300 Coal -157 Coal
2023	50 Wind	**0** Wind	**0** Wind	**0** Wind	**0** Wind
2024	50 Wind	**300** Coal **0** Wind	50 Wind	50 Wind	50 Wind
2025	0 Wind	**50** Wind	0 Wind	**50** Wind **150** CT	**50** Wind
2026	50 Wind	**0** Wind	50 Wind	50 Wind	50 Wind **150** CT
2027	50 Wind	50 Wind	50 Wind	50 Wind	**0** Wind
Egy Eff by 2027	161	383	383	0	69
Wind by 2027	665	615	665	715	665
Cogen by 2027	160	160	160	160	160
Coal by 2027	300	300	0	300	300

(note: Coal by 2027 does not include GGS)

Exhibit 9.6-2 compares IRP model results for the additional four plans to the Mod1 plan. A review of this exhibit generally indicates that all of the plans with some amount of energy efficiency are relatively close to one another, in terms of the expected value of the NPV of wholesale revenue requirements. The plan with the Base level of energy efficiency (Mod1) has the lowest expected value cost, although the plans with High energy efficiency assumptions are only slightly more expensive. The plan with no additional energy efficiency reductions was the most expensive of the four additional plans that were analyzed. These results tend to support increasing the action item goal for energy efficiency to at least the Base assumption levels.

Exhibit 9.6-2 Results for Additional Energy Efficiency Resource

	Mod1	Mod4	Mod5	Mod6	Mod7
Energy Efficiency Assumption	Base	High	High	None	Low
Demand Reduction by 2027[1]	161	383	383	0	69
NPV of EE Pgm Costs[2]	105	498	498	0	33
EV Revenue Requirements[2]	12,900	12,987	12,988	13,088	13,015
Ranking	1	2	3	5	4
Percent above Top Plan	0.00%	0.67%	0.68%	1.46%	0.89%

[1] Cumulative MW reduction including 15% RCO benefit
[2] Millions of 2007 NPV dollars

9.7 Summary

- As expected, the minimal resource plans tend to perform better under the low CO_2 cost scenario, and the moderate resource plans perform better under the base CO_2 cost scenario. What wasn't expected is that the moderate and minimal resource plans generally performed better than the extreme resource plans under the high CO_2 cost scenario. One potential reason may be due to the fact the IRP model allowed NPPD to purchase an unlimited amount of CO_2 emissions if its emissions exceeded the amount of free allowances. Thus, the risk of not being able to purchase CO_2 allowances was not included in the model; however this risk is designated for further study in the Action Plan, Section 10.7.
- The top resource plan based on the lowest NPV wholesale revenue requirements was Mod1. The next two lowest plans, Mod3 and Min4, had NPV costs within 1.0% of Mod1. The fourth lowest cost plan, Min1, had NPV costs within 1.2% of Mod1. The top four lowest cost plans also had the lowest relative risk as shown in the flying bar and tail value curves. Also, removing the wind generation development and the energy efficiency did not lower the overall cost of the Min5 plan when compared to the top resource plans.

- The major risk in the future is CO_2. Approximately one half of the uncertainty modeled is due to CO_2.
- As a rough estimate of the cost effect from the expected value for CO_2 costs (compared to no CO_2 cost), the overall NPV costs for the study period were 9% higher and the end-of-study nominal costs were 27% higher. The effect from using the high CO_2 cost was 21% higher for the study period and 60% higher at the end of the study period than if there was no CO_2 cost.
- Mod1 and Mod3 resource plans tend to put NPPD in a better economic position than Min1 and Min4 when looking beyond the IRP study period. The same is true of CO_2 emissions, but realize that the absolute amount of CO_2 emissions continues to grow for NPPD with Mod1 and Mod3 resource plans, although at a much lower rate than the overall load growth.

In the short term (through 2014), the four lowest cost plans are very similar to one another. The only differences are in energy efficiency and cogeneration assumptions. The major change occurs in the 2017-2022 time period, when the next major resources are installed. Refer to **Exhibit 8.1-1** for a summary of the amount and timing of the new resource additions for the four lowest cost resource plans. Sample load and capability graphs for the Mod1 resource plan are included in Appendix C as Exhibit C-3 for the summer season and Exhibit C-4 for the winter season.

10. NEXT STEPS / ACTION ITEMS

For action items that relate to measurable goals, 2008 shall be the base reference year.

10.1 Energy Efficiency, Conservation and Demand Response

Energy efficiency is a "least cost" resource that should be considered first in resource planning. The plans that performed best in the IRP analysis included energy efficiency savings of between 7% and 14% of NPPD's annual load growth by 2027. This equates to a potential demand reduction of between 69 MW and 161 MW by 2027. Analysis of additional resource plans verified that energy efficiency reductions in this range are economically beneficial. NPPD has traditionally had a very strong demand response program (e.g. irrigation load control) that in 2007 accounted for an effective demand reduction of approximately 572 MW.

Even though NPPD has maintained a presence with energy efficiency and education programs focused on helping customers improve their utilization of electricity, NPPD has not had a focused effort in the area of energy efficiency and conservation for a number of years prior to 2007. During 2007 NPPD hired a manager with specific responsibility for energy efficiency and conservation.

ACTION 10.1.a – Design, implement, and verify energy efficiency programs that can be utilized by NPPD's customers to improve conservation and utilization of electricity provided by NPPD. At least 41,100 MWh should be met through energy efficiency and conservation programs by 2014. This energy equates to 14% of NPPD's annual energy load growth or 0.25% of total native load.

10.2 Renewable Energy Resources

The plans that performed best in the IRP analysis included between 415 MW and 665 MW of new generation from wind energy by 2027. Also, NPPD released a RFP in 2007 to purchase wind energy from private or C-BED that were interested in developing a wind energy product in NPPD's service territory. By the end of April 2008, two power purchase agreements for a total of approximately 120 MW were executed.

Wind is primarily an energy resource that is variable in nature. This can potentially cause operational impacts in systems with large amounts of wind capacity installed in relation to peak system native load (i.e., wind integration impacts). Also, the best wind regions in Nebraska are located in rural parts of the state away from load centers. Therefore, additional investments in wind generation will potentially require significant additional investments in transmission. The IRP modeled costs associated with operational impacts and transmission investments to support wind generation. However, there is still uncertainty in these costs and additional studies should be performed before committing to investments beyond 415 MW to 665 MW of new wind generation.

ACTION 10.2.a – Complete negotiation of a Power Purchase Agreement for up to 30 MW more of wind energy for delivery to NPPD starting in 2008 or 2009. Note: By the end of April 2008 the District has contracted for approximately 120 MW of the original 150 MW of wind energy additions authorized by the Board in October 2007 to be delivered starting in 2008 or 2009. The total renewable energy addition is to be approximately 551,000 MWh per year.

ACTION 10.2.b – Construct or purchase an additional 100 MW to 150 MW of wind energy for delivery to NPPD starting in the 2014 to 2016 timeframe.

ACTION 10.2.c – Complete a study of the operational impacts of adding significant amounts of variable renewable energy resources to NPPD's system. This study would be more meaningful if done in conjunction with other Nebraska utilities (e.g., Nebraska Power Association [NPA]) and/or regional utilities.

ACTION 10.2.d – Complete a study of transmission systems needed to support significant amounts of new wind generation in the state. This study would be more meaningful if done in conjunction with other Nebraska utilities (NPA) and/or regional utilities.

10.3 Peaking Resources

Only one of the top four performing plans contemplated installing new peaking resources (approx. 150 MW in the 2020 timeframe). However, two of the remaining three plans contemplate installing a new combined cycle facility (approximately 237 MW) in the 2018 to 2021 timeframe. Also, NPPD's current fleet of combustion turbines is aging. Even though the current combustion turbines should be capable of providing peaking needs well into the future it would be prudent to pursue a strategy of evaluating and planning for new peaking units that could be installed in short order to meet changing operational or economic needs. If planned appropriately these units could be combined into a combined cycle facility as needs dictate.

The top performing plans also contemplate between 60 MW and 160 MW of cogeneration available on NPPD's system. Cogeneration is an attractive resource because of its high energy efficiency and resulting operational and environmental benefits. While NPPD can promote the benefits of cogeneration and help industrial customers evaluate cogeneration, the decision to install cogeneration ultimately resides with the customer. Therefore, pursuing a strategy that can use peaking units as a hedge against future capacity needs if cogeneration does not develop seems appropriate.

Peaking resources can be used as means to "firm up" the variable energy from wind resources. New peaking resources should be considered in developing a mitigation strategy for wind integration impacts.

ACTION 10.3.a – Study the economic and operational benefits of installing new peaking generation to provide a hedge against aging combustion turbine fleet issues, lack of cogeneration development, and wind integration impacts.

10.4 Intermediate Resources

Two of the top performing expansion plans contemplate installing a new combined cycle facility (approximately 237 MW) in the 2018 to 2021 timeframe. The utility industry seems to be favoring installation of additional natural gas fired generation units in lieu of coal fired units. This is primarily due to improved environmental benefits and a perceived easier path for permitting and constructing a natural gas fired generation facility over a coal fired generation facility. Increased reliance on natural gas as a fuel source for electrical generation will continue to increase the price and volatility of this fuel, which in turn increases the cost risk associated with natural gas fired generation. No further study is recommended at this time for a new natural gas combined cycle resource unless economic or operational needs change.

One of the top performing expansion plans contemplates installing 334 MW of hydro pumped storage in the 2019 timeframe. Pumped storage can be used as a means to "firm up" the variable energy from wind resources. Pumped storage can also add flexibility to the operation of the NPPD system especially since NPPD is a heavy baseload utility. It would be prudent to further study the economic and operational benefits of adding a pumped storage facility to NPPD's resource mix.

ACTION 10.4.a – Study the economic and operational benefits of adding a hydro pumped storage facility to NPPD's resource mix to hedge against wind integration impacts and improve the operational flexibility of the system.

10.5 Baseload Resources

A power uprate of Cooper Nuclear Station (CNS) was contemplated (approximately 49 MW in 2011 or 2012) in each of the top performing plans evaluated in the IRP. This is a very attractive baseload resource opportunity on a $/MWh basis. NPPD has also committed to submit a license renewal request to the NRC by September of 2008, which if approved by the NRC would extend the operating license of CNS to 2034. Any power uprate of CNS must be coordinated with the license renewal process. NPPD should complete project planning and develop a business case for completing a power uprate in the 2012 to 2014 timeframe.

Three of the top performing expansion plans contemplated installation of a new coal fired generating unit (approximately 300 MW) with the reduction of existing coal fired generation resources (approximately 157 MW) in the 2017 to 2022 timeframe. This is being driven primarily by the uncertainty around future environmental regulation, especially CO_2 regulation. In certain higher regulation cost scenarios it may be more economically beneficial to reduce output from an older less efficient existing unit, and repower or replace that unit with newer more efficient technology that has less environmental impact. However, since there is so much uncertainty about future environmental regulation and the cost of mitigation at this time further study should be undertaken prior to committing to a course of action that would include the reduction of an existing generation resource.

No other new baseload generation is contemplated prior to 2022 in any of the top performing plans. Given the uncertainty of future environmental regulation, study of new baseload generation needs beyond the 2018 to 2022 timeframe should focus on carbon neutral technologies, such as nuclear, fossil fired with carbon capture and storage, or other new clean coal technologies. Therefore, it would be prudent for NPPD to stay engaged in new generation research and development activities through NPPD's participation in the Nebraska Center for Energy Sciences Research, EPRI, and other industry organizations.

ACTION 10.5.a – Complete a strategic asset plan for NPPD's existing coal fired generation units.

ACTION 10.5.b – Seek opportunities to partner with industry organizations or other utilities to evaluate carbon neutral generation technologies.

ACTION 10.5.c – Complete project planning and develop a business case for completing a power uprate at CNS in the 2012 to 2014 timeframe.

10.6 Other Resources

Cogeneration is an attractive resource because of its high energy efficiency and resulting operational and environmental benefits. Cogeneration is also an excellent candidate for using bio-based renewable fuels to supplement or replace the normal fuel source. Promoting cogeneration provides NPPD with an opportunity to help our customers improve the efficiency of their operations and potentially generate additional environmental benefits. However, while NPPD can promote the benefits of cogeneration and help industrial customers evaluate cogeneration, the decision to install cogeneration ultimately resides with the customer.

NPPD also has an opportunity to work closely with the agricultural industry in Nebraska to develop and implement projects to use agricultural waste (e.g. methane digesters) to create electricity. These projects have the potential to provide economic benefit to farmers and ranchers, while improving the environment by capturing and consuming methane gas, which is approximately 20 times more powerful as a greenhouse gas than CO_2. These projects could create carbon offsets in a carbon regulated environment that could be sold or used to offset generation from traditional fossil resources.

NPPD should leverage its membership and participation in national and state organizations engaged in energy research in order to stay current with energy related technology development. NPPD is a member of the Electric Power Research Institute (EPRI), which conducts energy and utility related research for its member utilities. NPPD is also a founding member of the Nebraska Center for Energy Sciences Research (NCESR). The NCESR, a collaboration between NPPD and the University of Nebraska – Lincoln, was established in April 2006 to conduct research on renewable energy sources, energy efficiency, and energy conservation; and to expand economic opportunities and improve quality of life for Nebraska and the nation.

ACTION 10.6.a – Promote and support the development of cogeneration and distributed generation resources that provide economic and environmental benefit to NPPD and its customers. A goal of 100 MW of cogeneration should be added to NPPD's system by 2014.

ACTION 10.6.b – Work with NPPD's customers to develop and implement projects that use agricultural based methane or other waste products to generate electricity and create environmental offsets (e.g. carbon offsets).

ACTION 10.6.c – Engage in energy related research at the state (Nebraska Center for Energy Science Research at the University of Nebraska-Lincoln) and national level (Electric Power Research Institute).

10.7 Risk Associated With Availability and Price of CO_2 Allowances

As noted in Section 9.4, most of the resource plans studied depend heavily on the ability to purchase large numbers of CO_2 emission allowances. These results caused some concern about the risk associated with this assumption.

The results in Exhibits 9.4-2, 9.4-3, 9.4-4, and 9.5-1 are used as a foundation for a simplified evaluation of two risk perspectives in Exhibit 10.7-1 for year 2027:

- "What if" the CO_2 emission cost is $59/metric ton higher in 2027 than the IRP model value, as projected by the EPA in its March 14, 2008 "EPA Analysis of the Lieberman-Warner Climate Security Act of 2008" (S. 2191 in the 110th Congress)? The EPA estimated the 2030 price for a CO_2 allowance in 2030 to be $72/metric ton in 2005$, which translates to $107/metric ton in 2027 in nominal dollars, or $59/metric ton greater than the IRP's expected value of $48/metric ton. If so, how would the cost relationships change between the cases modeled.
- "What if" the extra CO_2 emission allowances are not available for purchase, then how much coal generation would need to be curtailed in 2027 (i.e., replaced by non-emitting generation)?

Exhibit 10.7-1 shows for the first "what if" that the Ext4 Plan becomes the lowest cost, by a small margin. The extra EPA-estimated cost for CO_2 draws the Ext4 Plan from being 10.8% higher than Mod1 to being the lowest cost plan (i.e., the Mod1 plan becomes 1.2% higher in cost than Ext1). Expectedly, the Min4 Plan becomes even higher in cost compared to the other two plans, going from 1.4% higher than Mod1 to 7.8% higher than Ext4.

For the second "what if", Exhibit 10.7-1 shows that 457 MW of coal capacity must be curtailed for the Ext4 Plan, 1,013 MW for the Mod1 Plan, and 1,313 MW for the Min4 Plan.

Exhibit 10.7-1 - Year 2027 CO_2 Emission Cost and Allowance Availability Risks

Reference	Min4 Plan Exhibit 9.4-2	Mod1 Plan Exhibit 9.4-3	Ext4 Plan Exhibit 9.4-4
Average Free CO2 Emission Allowances in Millions of Metric Tons	5.1	5.1	5.1
Average Purchase Requirement of Allowances (including Offsets)	9.2	7.1	3.2
Average Additional 2027 Cost if Allowance Price is $59/metric ton higher	$542,800,000	$418,900,000	$188,800,000
2027 Cost Rank from Exhibit 9.5-1 (with CO2 Cost as Modeled)	#2 (1.4% higher)	#1 (LOWEST)	#3 (10.8% higher)
2027 Cost Rank (if an additional $59/metric ton is added to the results of Exhibit 9.5-1 per EPA CO2 cost estimate)	#3 (7.8% higher)	#2 (1.2% higher)	#1 (LOWEST)
Amount of Coal MW to be curtailed in 2027 if no allowances/offsets are available (assuming coal at 80% capacity factor and CO2 emissions at 1 metric ton/MWh)	1,313	1,013	457

As pointed out in Section 9.5, none of these plans meet the 1990 emission levels in year 2027. Therefore, neither (a) these coal generation curtailments quantified in Exhibit 10.7-1 nor (b) these added payments for CO_2 emission allowances under the EPA cost estimate would actually satisfy the Lieberman-Warner proposal which calls for emissions in 2030 to be 11% below 1990 levels.

In addition to assessing the risk of depending on purchasing "unlimited allowances", it would be beneficial to explore further the benefits that curtailing coal generation, as done in the Ext4 Plan, for example, creates in combination with a high wind penetration. That is, if coal generation needed to be curtailed to comply with CO_2 emission limits, then can these coal generation variations serve as firming capacity for the wind variations (i.e., low coal generation coupled with high wind generation and high coal generation coupled with low wind generation)?

ACTION 10.7.a – Examine further the risk associated with the dependence on the availability and price of CO_2 allowances and offsets for compliance with potential greenhouse gas regulations.

11. APPENDICES

Appendix A – Customer Listing

NPPD WHOLESALE REQUIREMENTS CUSTOMERS
PUBLIC POWER DISTRICTS:

Utility Name	City, State	G&T Member*
Burt County PPD	Tekamah, NE	Yes
Butler PPD	David City, NE	Yes
Cedar-Knox PPD	Hartington, NE	Yes
Cornhusker PPD	Columbus, NE	Yes
Cuming County PPD	West Point, NE	Yes
Custer PPD	Broken Bow, NE	Yes
Dawson PPD	Lexington, NE	Yes
Elkhorn RPPD	Battle Creek, NE	Yes
Howard Greeley RPPD	St. Paul, NE	Yes
KBR RPPD	Ainsworth, NE	Yes
Loup Valleys RPPD	Ord, NE	Yes
McCook PPD	McCook, NE	Yes
Niobrara Valley EMC	O'Neill, NE	Yes
North Central PPD	Creighton, NE	Yes
Northeast Nebraska PPD	Emerson, NE	Yes
Perennial PPD	York, NE	Yes
Polk County RPPD	Stromsburg, NE	Yes
Seward County PPD	Seward, NE	Yes
South Central PPD	Nelson, NE	Yes
Southwest PPD	Palisade, NE	Yes
Stanton County PPD	Stanton, NE	Yes
Twin Valleys PPD	Cambridge, NE	Yes
Loup Power District	Columbus, NE	No
Norris PPD	Beatrice, NE	No
Southern PD	Grand Island, NE	No

NPPD WHOLESALE REQUIREMENTS CUSTOMERS
MUNICIPAL UTILITIES:

Utility Name	City, State	Direct WAPA Allocation
City of Arapahoe	Arapahoe, NE	
City of Auburn	Auburn, NE	Yes
City of Battle Creek	Battle Creek, NE	
City of Beatrice	Beatrice, NE	Yes
Village of Bradshaw	Bradshaw, NE	
Village of Brainard	Brainard, NE	
City of Central City	Central City, NE	
Village of Chester	Chester, NE	
City of Cozad	Cozad, NE	
Village of Davenport	Davenport, NE	
City of David City	David City, NE	Yes
City of Deshler	Deshler, NE	Yes
Village of DeWitt	DeWitt, NE	Yes
Village of Dorchester	Dorchester, NE	
City of Edgar	Edgar, NE	
Village of Fairmont	Faimont, NE	
City of Friend	Friend, NE	
Village of Giltner	Giltner, NE	
City of Gothenburg	Gothenburg, NE	
Village of Hampton	Hampton, NE	
City of Hebron	Hebron, NE	
Village of Hemingford	Hemingford, NE	
Village of Hildreth	Hildreth, NE	
City of Holdrege	Holdrege, NE	
City of Lexington	Lexington, NE	
Village of Lodgepole	Lodgepole, NE	Yes
City of Lyons	Lyons, NE	Yes
City of Madison	Madison, NE	Yes
City of Minden	Minden, NE	
City of Neligh	Neligh, NE	Yes
City of Nelson	Nelson, NE	
City of North Platte	North Platte, NE	
City of Ord	Ord, NE	Yes
Village of Polk	Polk, NE	
Village of Prague	Prague, NE	
City of Randolph	Randolph, NE	Yes
City of Scribner	Scribner, NE	
City of Seward	Seward, NE	
Village of Snyder	Snyder, NE	
City of South Sioux City	South Sioux City, NE	Yes
Village of Summerfield	Summerfield, KS	
City of Superior	Superior, NE	
City of Sutton	Sutton, NE	
City of Valentine	Valentine, NE	
City of Wahoo	Wahoo, NE	Yes
City of Wakefield	Wakefield, NE	Yes
Village of Walthill	Walthill, NE	
Village of Wauneta	Wauneta, NE	Yes
City of Wayne	Wayne, NE	Yes
City of Webber	Webber, KS	
Village of Wilcox	Wilcox, NE	
City of Wymore	Wymore, NE	

* Although these municipals currently purchase primarily non-firm energ from NPPD, there is in place an agreement which provides for the municipal to purchase and NPPD to provide firm power and energy to serve any load growth above the municipal's WAPA allocation plus existing generating capacity.

REQUIREMENTS CUSTOMERS OF
NPPD's WHOLESALE CUSTOMERS

Requirements Customer	Direct WAPA Allocation
Bartley, NE	
Belleville, KS	Yes
Cambridge, NE	Yes
Campbell, NE	
Clarkson, NE	
Decatur, NE	
Emerson, NE	Yes
Filley, NE	
Franklin, NE	Yes
Hickman, NE	
Holbrook, NE	
Hubbell, NE	
Indianola, NE	Yes
Laurel, NE	Yes
Leigh, NE	
Mullen, NE	Yes
Schuyler, NE	Yes
Spalding, NE	Yes
St. Paul, NE	
Stratton, NE	
Stromsburg, NE	
Trenton, NE	
Weston, NE	
Wilber, NE	Yes
Winside, NE	Yes
Wayne State College	Yes
Beatrice SDC	Yes
Santee Sioux Tribe	Yes
Omaha Tribe	Yes

NPPD Retail Customers

Norfolk Veterans Home	Direct WAPA Allocation - Yes
Winnebago Tribe	Direct WAPA Allocation - Yes
Oglala Sioux Tribe	Direct WAPA Allocation - Yes

NPPD Retail Towns

Ainsworth	Geneva	Ogallala
Alma	Gibbon	O'Neill
Anoka	Gordon	Oshkosh
Ashton	Hartington	Pawnee City
Atkinson	Hay Springs	Pine Ridge
Aurora	Homer	Plattsmouth
Barada	Humboldt	Pleasant Dale
Bassett	Inman	Ravenna
Big Springs	Kearney	Rushville
Bloomfield	Lewellen	Scottsbluff
Brandon	Lewiston	Shelton
Bristow	Lisco	Shubert
Broadwater	Long Pine	St. Mary
Brule	Loup City	Steinauer
Burchard	Lynch	Stella
Butte	Madrid	Sterling
Chadron	McCook	Sutherland
Clinton	McGrew	Table Rock
Crab Orchard	Meadow Grove	Tekamah
Craig	Melbeta	Terrytown
Crawford	Merriman	Tilden
Creighton	Milford	Union
Crystal Lake	Minatare	Venango
Dakota City	Murray	Verdon
Dawson	Mynard	Whiteclay
DuBois	Nehawka	Whitney
Elm Creek	Norfolk	Winnebago
Elsie	Northport	York
Emmet	Oakdale	
Fort Robinson	Oakland	

Retail Customers of NPPD's Wholesale Customers

Abie	Chambers	Fordyce	Linwood	Ong	Springranch
Adams	Chapman	Fullerton	Litchfield	Orchard	Springview
Agnew	Clarks	Funk	Loma	Orleans	St. Bernard
Akron	Clatonia	Gandy	Loomis	Osceola	St. Edward
Albion	Clay Center	Garland	Loretto	Osmond	St. Helena
Alda	Clearwater	Garrison	Lowell	Overton	St. James
Alexandria	Closter	Gates	Lushton	Page	St. Libory
Allen	Cody	Genoa	Macon	Palisade	St. Stephens
Almeria	Coleridge	Glenvil	Macy	Palmer	Stamford
Aloys	Columbus	Goehner	Magnet	Panama	Stanton
Altona	Comstock	Grafton	Malcolm	Parks	Staplehurst
Amelia	Concord	Greeley	Malmo	Pauline	Stapleton
Amherst	Cordova	Gresham	Marion	Petersburg	Stockham
Angus	Cornlea	Gross	Marquette	Phillips	Stockville
Anselmo	Cortland	Guide Rock	Martell	Pickrell	Strang
Arcadia	Cotesfield	Hadar	Martinsburg	Pilger	Sumner
Archer	Cowles	Haigler	Mascot	Platte Center	Surprise
Assumption	Creston	Hallam	Maskell	Pleasant Dale	Swan Lake
Atlanta	Crofton	Halsey	Mason City	Pleasant Hill	Swanton
Axtell	Crookston	Hamlet	Max	Pleasanton	Swedehome
Ayr	Crowell	Hansen	Maxwell	Plymouth	Sweetwater
Bancroft	Culbertson	Hardy	McCool Junction	Ponca	Tamora
Barneston	Cushing	Harvard	McLean	Poole	Tarnov
Bartlett	Danbury	Havens	Merna	Powell	Taylor
Bazile Mills	Dannebrog	Hayes Center	Midway	Primrose	Thayer
Beaver Crossing	Darr	Hayland	Milburn	Princeton	Thedford
Bee	Davey	Hazard	Miller	Prosser	Thurston
Beemer	Daykin	Heartwell	Milligan	Purdum	Tobias
Belden	Denman	Henderson	Mills	Raeville	Toughy
Belgrade	Denton	Hendley	Monowi	Ragan	Trumbull
Bellwood	Deweese	Hershey	Monroe	Raymond	Tryon
Belvidere	Diller	Holland	Monterey	Republican City	Uehling
Benedict	Dixon	Hollinger	Moorefield	Richland	Ulysses
Bertrand	Dodge	Holmesville	Mt. Clare	Rising City	Upland
Berwyn	Doniphan	Holstein	Murphy	Riverdale	Utica
Beverly	Duncan	Hordville	Naper	Riverton	Valparaiso
Bladen	Dunning	Hoskins	Naponee	Roca	Verdel
Bloomington	Dwight	Howells	Nemaha	Rockford	Verdigre
Blue Springs	Eddyville	Hubbard	Nenzel	Rockville	Verona
Boelus	Edison	Humphrey	Newark	Rokeby	Virginia
Boone	Elba	Huntley	Newcastle	Rosalie	Waco
Bostwick	Eldorado	Inavale	Newman Grove	Rose	Waterbury
Bow Valley	Elgin	Inland	Newport	Roseland	Wausa
Brady	Elsmere	Jackson	Niobrara	Rosemont	Webster
Brewster	Elwood	Jamison	Nora	Rosenburg	Weissert
Brownlee	Elyria	Johnson	Norden	Royal	Wellfleet
Brownville	Enders	Johnstown	Norman	Ruby	Western
Bruning	Enola	Keene	North Loup	Ruskin	Westerville
Bruno	Ericson	Kenesaw	North Star	Santee	Willis
Brunswick	Eustis	Kennedy	Nysted	Saronville	Willow Island
Burton	Ewing	Kilgore	Oak	Scotia	Wilsonville
Byron	Exeter	Kramer	Obert	Seneca	Winnetoon
Cairo	Fairfield	Kronberg	Oconto	Shelby	Wolbach
Carleton	Farnam	Lawrence	Octavia	Sholes	Wood Lake
Carroll	Farwell	Lebanon	Odell	Silver Creek	Wynot
Cedar Rapids	Firth	Liberty	Odessa	Smithfield	
Center	Flats	Lindsay	Ohiowa	Sprague	

Appendix B – Existing Generating Unit Data

Nebraska Public Power District

Generating Capability Data
2008 Existing Megawatts

Unit Name	Location	Unit Type	Fuel Type	Summer Rating	Winter Rating	Commercial Start Date
Auburn 1	Auburn, NE	IC	NG,FO2	2.10	2.10	1982
Auburn 2	Auburn, NE	IC	NG,FO2	0.50	0.50	1949
Auburn 4	Auburn, NE	IC	NG,FO2	3.30	3.30	1993
Auburn 5	Auburn, NE	IC	NG,FO2	3.00	3.00	1973
Auburn 6	Auburn, NE	IC	NG,FO2	2.20	2.20	1967
Auburn 7	Auburn, NE	IC	NG,FO2	5.20	5.20	1987
BPS	Beatrice, NE	CC	NG	237.00	250.00	2005
Belleville 4	Belleville, KS	IC	NG,FO2	0.00	0.00	1955
Belleville 5	Belleville, KS	IC	NG,FO2	1.40	1.40	1961
Belleville 6	Belleville, KS	IC	NG,FO2	2.50	2.50	1966
Belleville 7	Belleville, KS	IC	NG,FO2	3.30	3.30	1971
Belleville 8	Belleville, KS	IC	NG,FO2	2.80	2.80	2005
Cambridge	Cambridge, NE	IC	FO2	3.00	3.00	1958
Canaday	Lexington, NE	ST	NG, FO6	117.95	119.00	1958
Columbus 1	Columbus, NE	HY	WAT	15.00	15.00	1936
Columbus 2	Columbus, NE	HY	WAT	15.00	15.00	1936
Columbus 3	Columbus, NE	HY	WAT	15.00	15.00	1936
Cooper	Brownville, NE	NB	UR	769.73	800.00	1974
David City 1	David City, NE	IC	NG, FO2	1.30	1.30	1960
David City 2	David City, NE	IC	FO2	0.80	0.80	1949
David City 3	David City, NE	IC	NG, FO2	0.90	0.90	1955
David City 4	David City, NE	IC	NG, FO2	1.80	1.80	1966
David City 5	David City, NE	IC	FO2	1.33	1.33	1996
David City 6	David City, NE	IC	FO2	1.33	1.33	1996
David City 7	David City, NE	IC	FO2	1.34	1.34	1996
Deshler_1	Deshler, NE	IC	FO2	0.27	0.27	2001
Deshler_2	Deshler, NE	IC	FO2	0.29	0.29	1950
Deshler_3	Deshler, NE	IC	FO2	1.10	1.10	1998
Deshler_4	Deshler, NE	IC	FO2	0.60	0.60	1956
Emerson_2	Emerson, NE	IC	FO2	1.15	1.15	1968
Emerson_3	Emerson, NE	IC	FO2	0.15	0.15	1948
Emerson_4	Emerson, NE	IC	FO2	0.40	0.40	1958
Franklin 1	Franklin, NE	IC	NG, FO2	0.65	0.65	1963
Franklin 2	Franklin, NE	IC	NG, FO2	1.35	1.35	1974
Franklin 3	Franklin, NE	IC	NG, FO2	1.05	1.05	1968
Franklin 4	Franklin, NE	IC	NG, FO2	0.65	0.65	1955
Gentleman 1	Sutherland, NE	ST	BITW	665.00	665.00	1979
Gentleman 2	Sutherland, NE	ST	BITW	700.00	700.00	1982
Hallam	Hallam, NE	GT	NG, FO2	52.00	56.00	1973
Hebron	Hebron, NE	GT	FO2	51.00	55.00	1973
Jeffrey 1	Brady, NE	HY	WAT	9.00	9.00	1940
Jeffrey 2	Brady, NE	HY	WAT	9.00	9.00	1940
Johnson I 1	Lexington, NE	HY	WAT	9.00	9.00	1940
Johnson I 2	Lexington, NE	HY	WAT	9.00	9.00	1940
Johnson II	Lexington, NE	HY	WAT	18.00	18.00	1940
Kearney	Kearney, NE	HY	WAT	1.00	0.00	1921
Kingsley	Ogallala, NE	HY	WAT	37.52	37.30	1985

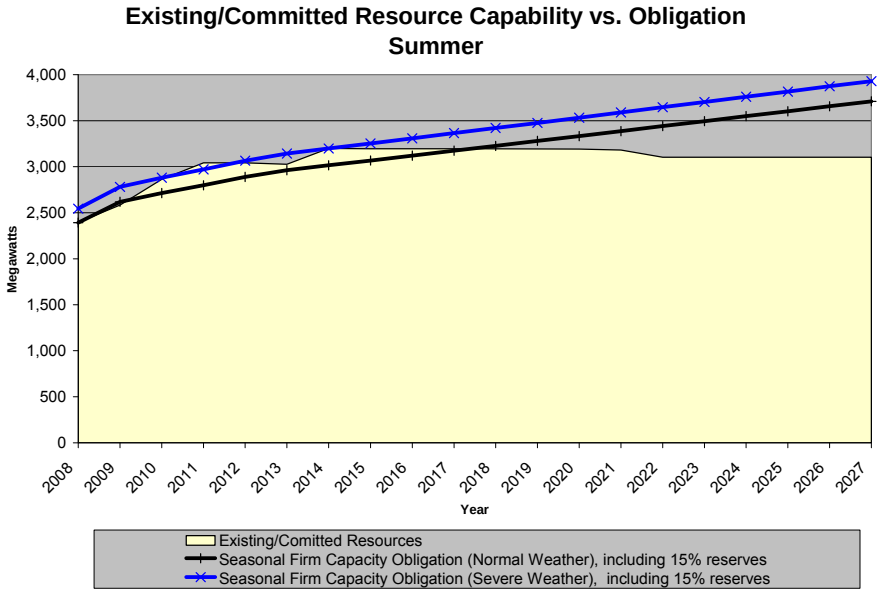
Nebraska Public Power District

Generating Capability Data
2008 Existing Megawatts

Unit Name	Location	Unit Type	Fuel Type	Summer Rating	Winter Rating	Commercial Start Date
Lyons 2	Lyons, NE	IC	FO2	0.20	0.20	1960
Lyons 3	Lyons, NE	IC	FO2	0.90	0.90	1953
Madison 1	Madison, NE	IC	NG, FO2	1.70	1.70	1969
Madison 2	Madison, NE	IC	NG, FO2	0.95	0.95	1959
Madison 3	Madison, NE	IC	NG, FO2	0.85	0.85	1953
Madison 4	Madison, NE	IC	FO2	0.50	0.50	1946
McCook	McCook, NE	GT	FO2	50.00	53.00	1973
Monroe	Monroe, NE	HY	WAT	2.30	1.20	1936
Mullen 1	Mullen, NE	IC	FO2	0.35	0.35	1958
Mullen 2	Mullen, NE	IC	FO2	0.65	0.65	1966
North Platte 1	North Platte, NE	HY	WAT	12.00	12.00	1937
North Platte 2	North Platte, NE	HY	WAT	12.00	12.00	1937
Ord 1	Ord, NE	IC	NG, FO2	5.00	5.00	1973
Ord 2	Ord, NE	IC	NG, FO2	1.00	1.00	1966
Ord 3	Ord, NE	IC	NG, FO2	2.00	2.00	1963
Ord 4	Ord, NE	IC	FO2	1.40	1.40	1997
Ord 5	Ord, NE	IC	FO2	1.40	1.40	1997
Sheldon 1	Hallam, NE	ST	BITW	105.00	105.00	1961
Sheldon 2	Hallam, NE	ST	BITW	120.00	120.00	1968
Spalding	Spalding, NE	IC	FO2	2.25	2.25	1955
Spencer 1	Spencer, NE	HY	WAT	1.00	1.00	1927
Spencer 2	Spencer, NE	HY	WAT	0.80	0.80	1952
Sutherland 1	Sutherland, NE	IC	FO2	0.45	0.45	1952
Sutherland 2	Sutherland, NE	IC	FO2	0.85	0.85	1959
Sutherland 3	Sutherland, NE	IC	FO2	0.00	0.00	1935
Sutherland 4	Sutherland, NE	IC	FO2	1.35	1.35	1964
Wahoo_1	Wahoo, NE	IC	NG,FO2	1.70	1.70	1960
Wahoo_3	Wahoo, NE	IC	NG,FO2	3.60	3.60	1973
Wahoo_5	Wahoo, NE	IC	NG,FO2	1.80	1.80	1952
Wahoo_6	Wahoo, NE	IC	NG,FO2	2.90	2.90	1969
Wakefield 2	Wakefield, NE	IC	NG, FO2	0.54	0.54	1955
Wakefield 4	Wakefield, NE	IC	NG, FO2	0.69	0.69	1961
Wakefield 5	Wakefield, NE	IC	NG, FO2	1.08	1.08	1966
Wakefield 6	Wakefield, NE	IC	NG, FO2	1.13	1.13	1971
Wayne 1	Wayne, NE	IC	FO2	0.75	0.75	1951
Wayne 3	Wayne, NE	IC	FO2	1.75	1.75	1956
Wayne 4	Wayne, NE	IC	FO2	1.85	1.85	1960
Wayne 5	Wayne, NE	IC	FO2	3.25	3.25	1966
Wayne 6	Wayne, NE	IC	FO2	4.90	4.90	1968
Wayne 7	Wayne, NE	IC	FO2	3.25	3.25	1998
Wayne 8	Wayne, NE	IC	FO2	3.25	3.25	1998
Wilber	Wilber, NE	IC	FO2	2.94	2.94	1949
Wind	Ainsworth, NE			9.06	23.35	2005
York 1	York, NE	IC	FO2	1.00	1.00	1980
York 2	York, NE	IC	FO2	1.60	1.60	1996
Total				3147.9	3215.2	

Appendix C – Projected Load & Capability Graphs

Exhibit C-1 – Load & Capability with Only Existing/Committed Resources, Summer Season



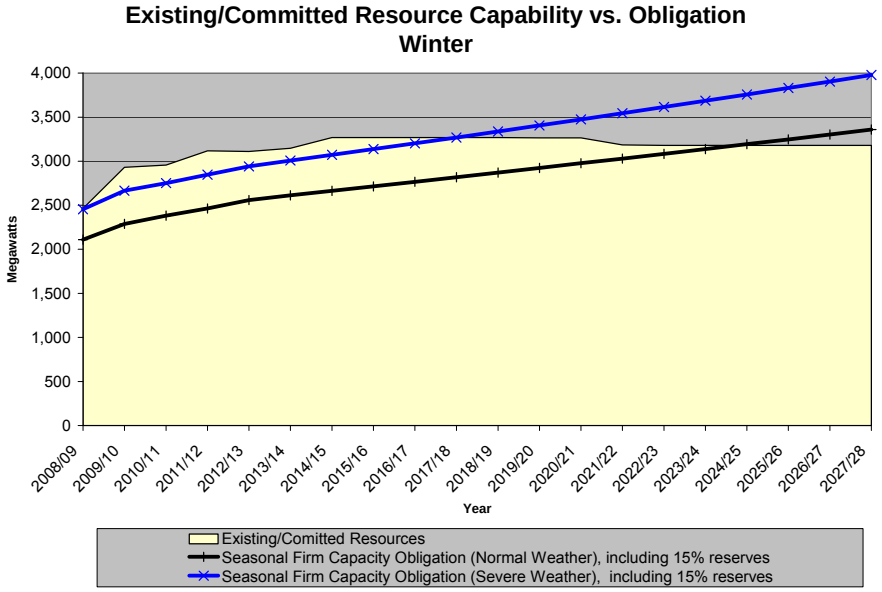
SUMMER Load Forecast Scenario is: **Severe Weather Billable; Base Economic Forecast**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1 Seasonal Billable Demand (Summer)	2,638	2,842	2,928	3,000	3,081	3,148	3,195	3,242	3,289	3,337	3,385	3,432	3,480	3,528	3,577	3,625	3,673	3,721	3,770	3,818
2 Annual Peak Demand	2,825	3,047	3,142	3,222	3,313	3,388	3,442	3,496	3,550	3,606	3,661	3,715	3,771	3,827	3,884	3,940	3,996	4,052	4,110	4,166
3 Firm Purchases (with reserves)-Committed	451	451	451	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446
4 Firm Sales (with reserves)-Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Billable Demand = 1-3+4	2,188	2,392	2,478	2,554	2,635	2,702	2,749	2,796	2,843	2,891	2,939	2,986	3,034	3,082	3,131	3,179	3,227	3,275	3,324	3,372
6 AnAnnual Adjusted Billable Demand = 2-3+4	2,375	2,596	2,691	2,776	2,867	2,942	2,996	3,050	3,104	3,160	3,215	3,269	3,325	3,381	3,438	3,494	3,550	3,606	3,664	3,720
7 Accredited Generating Capability (Base Summer Exist & Committed)	3,143	3,330	3,360	3,390	3,390	3,373	3,373	3,370	3,370	3,370	3,370	3,366	3,366	3,356	3,279	3,279	3,279	3,279	3,279	3,279
7a Accredited Generating Capability (Summer Incremental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Unit Purchases (without reserves)-Summer Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8a Unit Purchases (without reserves)-Summer Incremental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Unit Sales (without reserves)-Summer Committed	747	747	497	347	347	345	175	175	175	175	175	175	175	175	175	175	175	175	175	175
9a Unit Sales (without reserves)-Summer Incremental	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+7a+8+8a-9-9a (Summer)	2,396	2,583	2,863	3,043	3,043	3,028	3,198	3,195	3,195	3,195	3,195	3,191	3,191	3,181	3,104	3,104	3,104	3,104	3,104	3,104
11 Reserve Capacity Obligation = 6 x 0.15	356	389	404	416	430	441	449	458	466	474	482	490	499	507	516	524	533	541	550	558
12 Total Seasonal Firm Capacity Obligation = 5+11	2,544	2,781	2,881	2,970	3,065	3,143	3,198	3,254	3,309	3,365	3,421	3,476	3,533	3,589	3,647	3,703	3,760	3,816	3,874	3,930
13 NORMAL Surplus or Deficit (-) Capacity = 10-12 (Summer)	**-148**	**-198**	**-18**	73	**-22**	**-116**	**-1**	**-59**	**-114**	**-170**	**-226**	**-285**	**-342**	**-408**	**-543**	**-599**	**-656**	**-712**	**-770**	**-826**

SUMMER Load Forecast Scenario is: **Normal Weather Billable; Base Economic Forecast**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1 Seasonal Billable Demand (Summer)	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629
2 Annual Peak Demand	2,686	2,897	2,986	3,063	3,149	3,220	3,272	3,323	3,375	3,427	3,479	3,533	3,585	3,638	3,692	3,745	3,799	3,852	3,906	3,960
3 Firm Purchases (with reserves)-Committed	451	451	451	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446
4 Firm Sales (with reserves)-Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Billable Demand = 1-3+4	2,058	2,252	2,333	2,406	2,483	2,546	2,591	2,636	2,681	2,726	2,771	2,817	2,862	2,908	2,954	3,000	3,046	3,091	3,137	3,183
6 Annual Adjusted Billable Demand = 2-3+4	2,236	2,446	2,536	2,617	2,703	2,774	2,826	2,877	2,929	2,981	3,033	3,087	3,139	3,192	3,246	3,299	3,353	3,406	3,460	3,514
7 Accredited Generating Capability (Base Summer Exist & Committed)	3,143	3,330	3,360	3,390	3,390	3,373	3,373	3,370	3,370	3,370	3,370	3,366	3,366	3,356	3,279	3,279	3,279	3,279	3,279	3,279
7a Accredited Generating Capability (Summer Incremental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Unit Purchases (without reserves)-Summer Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8a Unit Purchases (without reserves)-Summer Incremental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Unit Sales (without reserves)-Summer Committed	747	747	497	347	347	345	175	175	175	175	175	175	175	175	175	175	175	175	175	175
9a Unit Sales (without reserves)-Summer Incremental	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+7a+8+8a-9-9a (Summer)	2,396	2,583	2,863	3,043	3,043	3,028	3,198	3,195	3,195	3,195	3,195	3,191	3,191	3,181	3,104	3,104	3,104	3,104	3,104	3,104
11 Reserve Capacity Obligation = 6 x 0.15	335	367	380	393	406	416	424	432	439	447	455	463	471	479	487	495	503	511	519	527
12 Total Seasonal Firm Capacity Obligation = 5+11	2,393	2,618	2,713	2,799	2,889	2,962	3,015	3,068	3,120	3,173	3,226	3,280	3,333	3,387	3,441	3,495	3,549	3,602	3,656	3,710
13 NORMAL Surplus or Deficit (-) Capacity = 10-12 (Summer)	3	**-35**	150	245	155	65	183	127	75	22	**-31**	**-89**	**-142**	**-206**	**-337**	**-391**	**-445**	**-498**	**-552**	**-606**

Exhibit C-2 – Load & Capability with Only Existing/Committed Resource, Winter Season



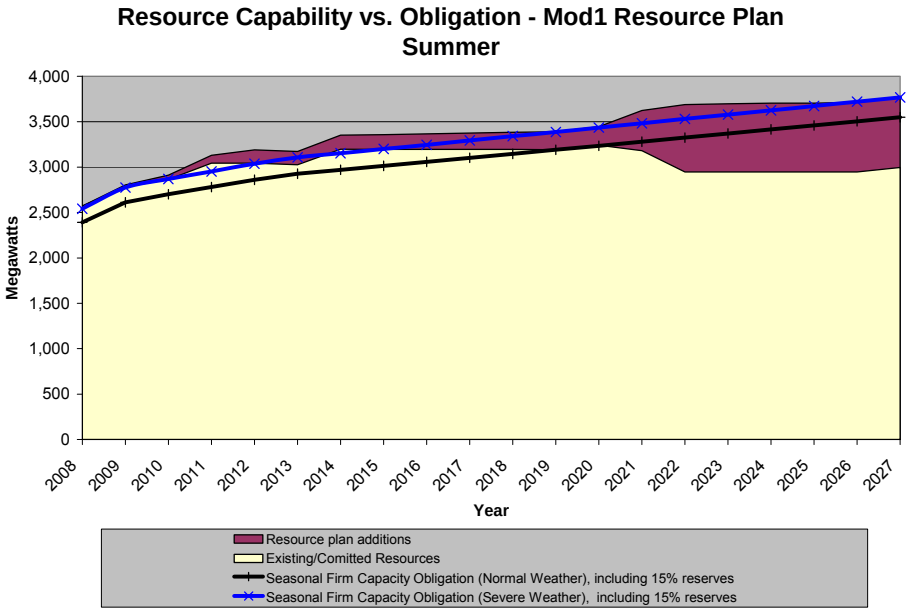
WINTER Load Forecast Scenario is: **Severe Weather Anytime; Base Economic Forecast**

	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
1 Seasonal Billable Demand (Winter)	2,240	2,417	2,488	2,570	2,650	2,706	2,762	2,819	2,877	2,935	2,995	3,055	3,115	3,177	3,239	3,302	3,365	3,429	3,494	3,560
2 Annual Peak Demand	2,825	3,047	3,142	3,222	3,313	3,388	3,442	3,496	3,550	3,606	3,661	3,715	3,771	3,827	3,884	3,940	3,996	4,052	4,110	4,166
3 Firm Purchases (with reserves)-Committed	182	182	181	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
4 Firm Sales (with reserves)-Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Billable Demand = 1-3+4	2,058	2,235	2,307	2,390	2,470	2,525	2,582	2,639	2,697	2,755	2,815	2,875	2,935	2,997	3,059	3,122	3,185	3,249	3,314	3,380
6 Annual Adjusted Billable Demand = 2-3+4	2,643	2,865	2,961	3,042	3,132	3,208	3,262	3,316	3,370	3,425	3,481	3,535	3,591	3,647	3,704	3,760	3,816	3,872	3,930	3,986
7 Accredited Generating Capability (Base Winter Exist & Committed)	3,210	3,427	3,453	3,464	3,456	3,447	3,444	3,444	3,444	3,444	3,444	3,441	3,441	3,359	3,353	3,353	3,353	3,353	3,353	3,353
7a Accredited Generating Capability (Winter Incremental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Unit Purchases (without reserves)-Winter Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8a Unit Purchases (without reserves)-Winter Incremental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Unit Sales (without reserves)-Winter Committed	747	497	497	347	346	300	175	175	175	175	175	175	175	175	175	175	175	175	175	175
9a Unit Sales (without reserves)-Winter Incremental	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+7a+8+8a-9-9a (Winter)	2,463	2,930	2,956	3,117	3,110	3,147	3,269	3,269	3,269	3,269	3,269	3,265	3,265	3,184	3,178	3,178	3,178	3,178	3,178	3,178
11 Reserve Capacity Obligation = 6 x 0.15	397	430	444	456	470	481	489	497	506	514	522	530	539	547	556	564	572	581	589	598
12 Total Seasonal Firm Capacity Obligation = 5+11	2,455	2,664	2,751	2,846	2,940	3,007	3,071	3,136	3,202	3,269	3,337	3,405	3,474	3,544	3,614	3,686	3,758	3,830	3,904	3,978
13 NORMAL Surplus or Deficit (-) Capacity = 10-12 (Winter)	9	266	205	271	170	140	198	133	67	**0**	**-68**	**-140**	**-209**	**-360**	**-437**	**-508**	**-580**	**-652**	**-726**	**-800**

WINTER Load Forecast Scenario is: **Normal Weather Anytime; Base Economic Forecast**

	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
1 Seasonal Billable Demand (Winter)	1,917	2,063	2,143	2,210	2,294	2,337	2,380	2,423	2,467	2,511	2,555	2,600	2,645	2,691	2,737	2,783	2,830	2,876	2,924	2,971
2 Annual Peak Demand	2,686	2,897	2,986	3,063	3,149	3,220	3,272	3,323	3,375	3,427	3,479	3,533	3,585	3,638	3,692	3,745	3,799	3,852	3,906	3,960
3 Firm Purchases (with reserves)-Committed	182	182	181	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
4 Firm Sales (with reserves)-Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Billable Demand = 1-3+4	1,735	1,882	1,962	2,030	2,114	2,156	2,199	2,243	2,286	2,330	2,375	2,420	2,465	2,511	2,557	2,603	2,649	2,696	2,744	2,791
6 Annual Adjusted Billable Demand = 2-3+4	2,504	2,715	2,805	2,883	2,969	3,040	3,092	3,143	3,195	3,247	3,299	3,352	3,405	3,458	3,512	3,565	3,619	3,672	3,726	3,780
7 Accredited Generating Capability (Base Winter Exist & Committed)	3,210	3,427	3,453	3,464	3,456	3,447	3,444	3,444	3,444	3,444	3,444	3,441	3,441	3,359	3,353	3,353	3,353	3,353	3,353	3,353
7a Accredited Generating Capability (Winter Incremental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Unit Purchases (without reserves)-Winter Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8a Unit Purchases (without reserves)-Winter Incremental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Unit Sales (without reserves)-Winter Committed	747	497	497	347	346	300	175	175	175	175	175	175	175	175	175	175	175	175	175	175
9a Unit Sales (without reserves)-Winter Incremental	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+7a+8+8a-9-9a (Winter)	2,463	2,930	2,956	3,117	3,110	3,147	3,269	3,269	3,269	3,269	3,269	3,265	3,265	3,184	3,178	3,178	3,178	3,178	3,178	3,178
11 Reserve Capacity Obligation = 6 x 0.15	376	407	421	433	445	456	464	472	479	487	495	503	511	519	527	535	543	551	559	567
12 Total Seasonal Firm Capacity Obligation = 5+11	2,110	2,289	2,383	2,462	2,559	2,612	2,663	2,714	2,766	2,818	2,870	2,923	2,976	3,029	3,083	3,138	3,192	3,247	3,303	3,358
13 NORMAL Surplus or Deficit (-) Capacity = 10-12 (Winter)	353	642	573	655	551	534	606	555	503	451	399	343	290	155	95	40	**-14**	**-69**	**-125**	**-180**

Exhibit C-3 – Load & Capability for Mod1 Resource Plan, Summer Season



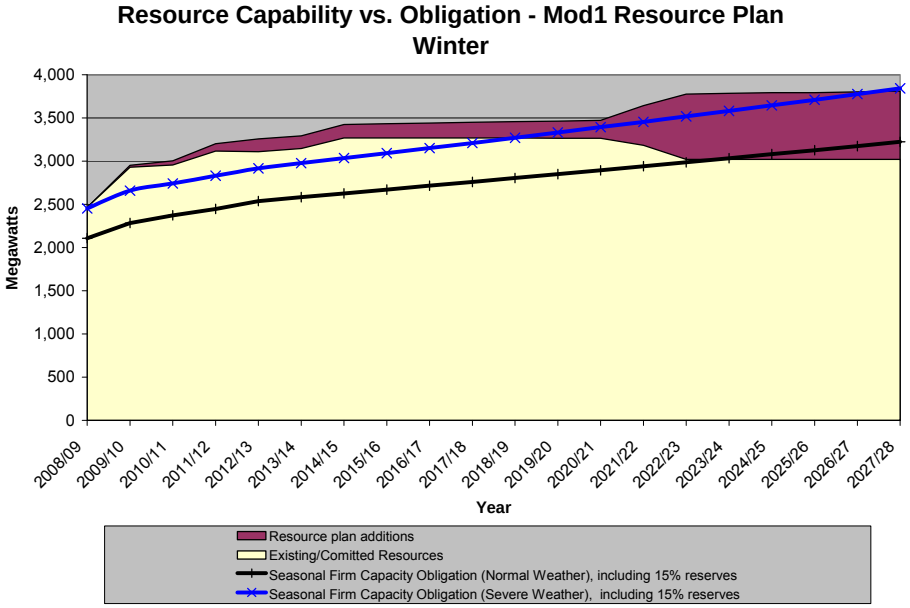
SUMMER Load Forecast Scenario is: **Severe Weather Billable; Base Economic Forecast**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1 Seasonal Billable Demand (Summer)	2,637	2,836	2,918	2,984	3,057	3,117	3,156	3,196	3,235	3,275	3,315	3,355	3,395	3,435	3,476	3,516	3,557	3,597	3,638	3,678
2 Annual Peak Demand	2,824	3,041	3,132	3,206	3,289	3,357	3,403	3,450	3,496	3,544	3,591	3,638	3,686	3,734	3,783	3,831	3,880	3,928	3,977	4,026
3 Firm Purchases (with reserves)-Committed	451	451	451	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446
4 Firm Sales (with reserves)-Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Billable Demand = 1-3+4	2,186	2,386	2,468	2,538	2,611	2,671	2,710	2,750	2,789	2,829	2,869	2,909	2,949	2,989	3,030	3,070	3,111	3,151	3,192	3,232
6 Annual Adjusted Billable Demand = 2-3+4	2,373	2,591	2,682	2,760	2,843	2,911	2,957	3,004	3,050	3,098	3,145	3,192	3,240	3,288	3,337	3,385	3,434	3,482	3,531	3,580
7 Accredited Generating Capability (Base Summer Exist & Committed)	3,143	3,330	3,360	3,390	3,390	3,373	3,373	3,370	3,370	3,370	3,370	3,366	3,366	3,356	3,054	3,054	3,054	3,054	3,054	3,054
7a Accredited Generating Capability (Summer Incremental)	0	21	48	86	146	146	155	163	172	180	189	197	206	442	742	751	759	759	768	776
8 Unit Purchases (without reserves)-Summer Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8a Unit Purchases (without reserves)-Summer Incremental	175	200	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	50
9 Unit Sales (without reserves)-Summer Committed	747	747	497	347	347	345	175	175	175	175	175	175	175	175	108	108	108	108	108	108
9a Unit Sales (without reserves)-Summer Incremental	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+7a+8+8a-9-9a (Summer)	2,571	2,804	2,911	3,129	3,189	3,174	3,352	3,358	3,366	3,375	3,383	3,388	3,447	3,624	3,689	3,697	3,706	3,706	3,714	3,773
11 Reserve Capacity Obligation = 6 x 0.15	356	389	402	414	426	437	444	451	458	465	472	479	486	493	501	508	515	522	530	537
12 Total Seasonal Firm Capacity Obligation = 5+11	2,542	2,774	2,870	2,952	3,038	3,108	3,154	3,200	3,246	3,294	3,341	3,388	3,435	3,482	3,531	3,578	3,626	3,673	3,722	3,769
13 NORMAL Surplus or Deficit (-) Capacity = 10-12 (Summer)	29	30	41	177	152	66	198	158	120	81	42	1	12	141	158	119	80	33	-7	4

SUMMER Load Forecast Scenario is: **Normal Weather Billable; Base Economic Forecast**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1 Seasonal Billable Demand (Summer)	2,507	2,696	2,773	2,836	2,905	2,961	2,998	3,036	3,073	3,110	3,147	3,186	3,223	3,261	3,299	3,337	3,376	3,413	3,451	3,489
2 Annual Peak Demand	2,685	2,891	2,977	3,048	3,125	3,189	3,233	3,277	3,321	3,365	3,410	3,455	3,500	3,545	3,591	3,637	3,683	3,728	3,774	3,820
3 Firm Purchases (with reserves)-Committed	451	451	451	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446
4 Firm Sales (with reserves)-Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Billable Demand = 1-3+4	2,056	2,246	2,323	2,390	2,459	2,515	2,552	2,590	2,627	2,664	2,701	2,740	2,777	2,815	2,853	2,891	2,930	2,967	3,005	3,043
6 Annual Adjusted Billable Demand = 2-3+4	2,234	2,440	2,526	2,602	2,679	2,743	2,787	2,831	2,875	2,919	2,964	3,009	3,054	3,099	3,145	3,191	3,237	3,282	3,328	3,374
7 Accredited Generating Capability (Base Summer Exist & Committed)	3,143	3,330	3,360	3,390	3,390	3,373	3,373	3,370	3,370	3,370	3,370	3,366	3,366	3,356	3,054	3,054	3,054	3,054	3,054	3,054
7a Accredited Generating Capability (Summer Incremental)	0	21	48	86	146	146	155	163	172	180	189	197	206	442	742	751	759	759	768	776
8 Unit Purchases (without reserves)-Summer Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8a Unit Purchases (without reserves)-Summer Incremental	175	200	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	50
9 Unit Sales (without reserves)-Summer Committed	747	747	497	347	347	345	175	175	175	175	175	175	175	175	108	108	108	108	108	108
9a Unit Sales (without reserves)-Summer Incremental	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+7a+8+8a-9-9a (Summer)	2,571	2,804	2,911	3,129	3,189	3,174	3,352	3,358	3,366	3,375	3,383	3,388	3,447	3,624	3,689	3,697	3,706	3,706	3,714	3,773
11 Reserve Capacity Obligation = 6 x 0.15	335	366	379	390	402	411	418	425	431	438	445	451	458	465	472	479	486	492	499	506
12 Total Seasonal Firm Capacity Obligation = 5+11	2,391	2,612	2,702	2,780	2,861	2,926	2,970	3,014	3,058	3,102	3,146	3,191	3,235	3,280	3,325	3,370	3,415	3,459	3,504	3,549
13 NORMAL Surplus or Deficit (-) Capacity = 10-12 (Summer)	180	193	210	349	328	247	382	344	308	273	237	197	212	344	364	327	291	247	210	224

Exhibit C-4 – Load & Capability for Mod1 Resource Plan, Winter Season



WINTER Load Forecast Scenario is: **Severe Weather Anytime; Base Economic Forecast**

	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
1 Seasonal Billable Demand (Winter)	2,239	2,412	2,480	2,558	2,631	2,681	2,732	2,783	2,834	2,887	2,940	2,993	3,047	3,102	3,158	3,214	3,271	3,328	3,386	3,445
2 Annual Peak Demand	2,824	3,041	3,132	3,206	3,289	3,357	3,403	3,450	3,496	3,544	3,591	3,638	3,686	3,734	3,783	3,831	3,880	3,928	3,977	4,026
3 Firm Purchases (with reserves)-Committed	182	182	181	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
4 Firm Sales (with reserves)-Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Billable Demand = 1-3+4	2,057	2,230	2,300	2,378	2,451	2,501	2,552	2,603	2,654	2,706	2,759	2,813	2,867	2,922	2,978	3,034	3,091	3,148	3,206	3,265
6 Annual Adjusted Billable Demand = 2-3+4	2,642	2,859	2,951	3,026	3,109	3,177	3,223	3,269	3,316	3,364	3,411	3,458	3,506	3,554	3,603	3,651	3,699	3,748	3,797	3,846
7 Accredited Generating Capability (Base Winter Exist & Committed)	3,210	3,427	3,453	3,464	3,456	3,447	3,444	3,444	3,444	3,444	3,444	3,441	3,441	3,359	3,128	3,128	3,128	3,128	3,128	3,128
7a Accredited Generating Capability (Winter Incremental)	0	21	48	86	148	148	156	165	173	182	190	199	207	457	757	766	774	774	783	791
8 Unit Purchases (without reserves)-Winter Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8a Unit Purchases (without reserves)-Winter Incremental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Unit Sales (without reserves)-Winter Committed	747	497	497	347	346	300	175	175	175	175	175	175	175	175	108	108	108	108	108	108
9a Unit Sales (without reserves)-Winter Incremental	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+7a+8+8a-9-9a (Winter)	2,463	2,952	3,004	3,203	3,258	3,294	3,425	3,434	3,442	3,451	3,459	3,464	3,472	3,641	3,777	3,786	3,794	3,794	3,803	3,811
11 Reserve Capacity Obligation = 6 x 0.15	396	429	443	454	466	477	484	490	497	505	512	519	526	533	541	548	555	562	570	577
12 Total Seasonal Firm Capacity Obligation = 5+11	2,454	2,659	2,742	2,831	2,917	2,978	3,035	3,093	3,152	3,211	3,271	3,332	3,393	3,455	3,518	3,582	3,646	3,710	3,776	3,842
13 NORMAL Surplus or Deficit (-) Capacity = 10-12 (Winter)	10	293	262	372	340	317	390	341	291	240	188	132	79	186	259	204	149	84	27	-31

WINTER Load Forecast Scenario is: **Normal Weather Anytime; Base Economic Forecast**

	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
1 Seasonal Billable Demand (Winter)	1,915	2,059	2,135	2,198	2,275	2,312	2,349	2,386	2,424	2,462	2,500	2,538	2,577	2,616	2,656	2,695	2,735	2,775	2,816	2,857
2 Annual Peak Demand	2,685	2,891	2,977	3,048	3,125	3,189	3,233	3,277	3,321	3,365	3,410	3,455	3,500	3,545	3,591	3,637	3,683	3,728	3,774	3,820
3 Firm Purchases (with reserves)-Committed	182	182	181	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
4 Firm Sales (with reserves)-Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Billable Demand = 1-3+4	1,733	1,877	1,954	2,017	2,095	2,132	2,169	2,206	2,244	2,282	2,320	2,358	2,397	2,436	2,475	2,515	2,555	2,595	2,636	2,677
6 Annual Adjusted Billable Demand = 2-3+4	2,503	2,709	2,796	2,867	2,945	3,009	3,053	3,097	3,141	3,185	3,230	3,275	3,320	3,365	3,411	3,457	3,503	3,547	3,594	3,640
7 Accredited Generating Capability (Base Winter Exist & Committed)	3,210	3,427	3,453	3,464	3,456	3,447	3,444	3,444	3,444	3,444	3,444	3,441	3,441	3,359	3,128	3,128	3,128	3,128	3,128	3,128
7a Accredited Generating Capability (Winter Incremental)	0	21	48	86	148	148	156	165	173	182	190	199	207	457	757	766	774	774	783	791
8 Unit Purchases (without reserves)-Winter Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8a Unit Purchases (without reserves)-Winter Incremental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Unit Sales (without reserves)-Winter Committed	747	497	497	347	346	300	175	175	175	175	175	175	175	175	108	108	108	108	108	108
9a Unit Sales (without reserves)-Winter Incremental	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+7a+8+8a-9-9a (Winter)	2,463	2,952	3,004	3,203	3,258	3,294	3,425	3,434	3,442	3,451	3,459	3,464	3,472	3,641	3,777	3,786	3,794	3,794	3,803	3,811
11 Reserve Capacity Obligation = 6 x 0.15	375	406	419	430	442	451	458	465	471	478	485	491	498	505	512	519	525	532	539	546
12 Total Seasonal Firm Capacity Obligation = 5+11	2,109	2,284	2,374	2,448	2,537	2,584	2,627	2,671	2,715	2,759	2,804	2,850	2,895	2,941	2,987	3,034	3,080	3,127	3,175	3,223
13 NORMAL Surplus or Deficit (-) Capacity = 10-12 (Winter)	355	668	630	756	721	711	798	763	727	691	655	614	578	700	790	752	714	667	628	589

Appendix D – Expansion Plans

Minimal Regulation Scenario – Base Case

Minimal Regulation Scenario - Base Case

Sheet Name = Min1

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	28	24	26	128	77	2	129	74	31	4	172	116	64	1	180	127	75	31	4	235	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.3%	1.4%	1.5%	1.6%	
Energy Efficiency (% of billable demand)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.4%	1.5%	1.6%	1.6%	
Egy Eff (MW + 15% for reserves)	1	2	4	7	10	13	16	20	23	27	31	35	39	43	47	51	55	60	64	69	
RPS Requirement (MWh) - Base N.L.	0	0	67,848	175,006	288,841	408,442	529,287	654,296	783,526	837,293	892,590	949,434	1,007,842	1,067,830	1,129,412	1,192,605	1,257,422	1,323,877	1,391,983	1,461,753	
RPS reduction from Energy Efficiency (MWh)	0	0	-95	-377	-875	-1,587	-2,519	-3,685	-5,095	-6,173	-7,356	-8,648	-10,052	-11,572	-13,213	-14,978	-16,871	-18,896	-21,058	-23,359	
Net RPS Requirement (MWh)	0	0	67,753	174,630	287,966	406,855	526,768	650,611	778,431	831,120	885,234	940,787	997,791	1,056,258	1,116,199	1,177,627	1,240,551	1,304,980	1,370,926	1,438,395	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.9%	41.8%	41.8%	41.8%	41.8%	41.7%	41.7%	41.7%	41.5%	41.5%	41.3%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	50	50	100	100	150	150	150	150	200	200	200	250	250	300	
Solar																					
Renewable Cogen (MW)																					
Accredited MW of new RPS wind	0	0	0	0	0	0	9	9	17	17	26	26	26	26	34	34	34	43	43	51	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil																					
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	
150 MW CT																					
New CC											237	237	237	237	237	237	237	237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen		10	20	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
Baseload Coal w/ 5% Biomass																					
New Baseload Coal															300	300	300	300	300	600	
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200								25									25		
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	50	50	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	0	300	0	0	0	0	300	757
NGCC	0	0	0	0	0	0	0	0	0	0	237	0	0	0	0	0	0	0	0	0	237
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	50	0	50	0	50	0	0	0	50	0	0	50	0	50	415
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	25	0	0	0	0	0	0	0	0	25	0	425

Min1 – cogen + CT – CC, move up coal

Min1 - cogen + CT - CC, move up coal

Sheet Name = Min2

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	28	4	136	228	177	102	229	174	131	79	35	4	227	164	43	-10	13	194	142	98	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.3%	1.4%	1.5%	1.6%	
Energy Efficiency (% of billable demand)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.4%	1.5%	1.6%	1.6%	
Egy Eff (MW + 15% for reserves)	1	2	4	7	10	13	16	20	23	27	31	35	39	43	47	51	55	60	64	69	
RPS Requirement (MWh) - Base N.L.	0	0	67,848	175,006	288,841	408,442	529,287	654,296	783,526	837,293	892,590	949,434	1,007,842	1,067,830	1,129,412	1,192,605	1,257,422	1,323,877	1,391,983	1,461,753	
RPS reduction from Energy Efficiency (MWh)	0	0	-95	-377	-875	-1,587	-2,519	-3,685	-5,095	-6,173	-7,356	-8,648	-10,052	-11,572	-13,213	-14,978	-16,871	-18,896	-21,058	-23,359	
Net RPS Requirement (MWh)	0	0	67,753	174,630	287,966	406,855	526,768	650,611	778,431	831,120	885,234	940,787	997,791	1,056,258	1,116,199	1,177,627	1,240,551	1,304,980	1,370,926	1,438,395	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.9%	41.8%	41.8%	41.8%	41.8%	41.7%	41.7%	41.7%	41.5%	41.5%	41.3%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	50	50	100	100	150	150	150	150	200	200	200	250	250	300	
Solar																					
Renewable Cogen (MW)																					
Accredited MW of new RPS wind	0	0	0	0	0	0	9	9	17	17	26	26	26	26	34	34	34	43	43	51	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil																					
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen																					
150 MW CT		150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	
New CC																					
New Coal or Nuclear																					
Coal-fired Cogen																					
Baseload Coal w/ 5% Biomass																					
New Baseload Coal													300	300	300	300	300	600	600	600	
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	50										25					75				
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	300	0	0	0	0	300	0	0	757
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT	0	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	50	0	50	0	50	0	0	0	50	0	0	50	0	50	415
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	50	0	0	0	0	0	0	0	0	0	25	0	0	0	0	75	0	0	0	325

Min1 – cogen – CC, move up 1st coal – 2nd coal + CT + CC

Min1 - cogen - CC, move up 1st coal - 2nd coal + CT + CC

Sheet Name = Min3

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	28	4	11	78	27	2	79	24	6	229	185	129	77	14	43	15	13	131	79	35	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.3%	1.4%	1.5%	1.6%	
Energy Efficiency (% of billable demand)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.4%	1.5%	1.6%	1.6%	
Egy Eff (MW + 15% for reserves)	1	2	4	7	10	13	16	20	23	27	31	35	39	43	47	51	55	60	64	69	
RPS Requirement (MWh) - Base N.L.	0	0	67,848	175,006	288,841	408,442	529,287	654,296	783,526	837,293	892,590	949,434	1,007,842	1,067,830	1,129,412	1,192,605	1,257,422	1,323,877	1,391,983	1,461,753	
RPS reduction from Energy Efficiency (MWh)	0	0	-95	-377	-875	-1,587	-2,519	-3,685	-5,095	-6,173	-7,356	-8,648	-10,052	-11,572	-13,213	-14,978	-16,871	-18,896	-21,058	-23,359	
Net RPS Requirement (MWh)	0	0	67,753	174,630	287,966	406,855	526,768	650,611	778,431	831,120	885,234	940,787	997,791	1,056,258	1,116,199	1,177,627	1,240,551	1,304,980	1,370,926	1,438,395	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.9%	41.8%	41.8%	41.8%	41.8%	41.7%	41.7%	41.7%	41.5%	41.5%	41.3%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	50	50	100	100	150	150	150	150	200	200	200	250	250	300	
Solar																					
Renewable Cogen (MW)																					
Accredited MW of new RPS wind	0	0	0	0	0	0	9	9	17	17	26	26	26	26	34	34	34	43	43	51	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil																					
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen																					
150 MW CT															150	150	150	150	150	150	
New CC																		237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen																					
Baseload Coal w/ 5% Biomass																					
New Baseload Coal										300	300	300	300	300	300	300	300	300	300	300	
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200	25			50			25							25	75				
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	300	0	0	0	0	0	0	0	0	0	0	457
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	237	0	0	237
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	0	0	0	0	0	150
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	50	0	50	0	50	0	0	0	50	0	0	50	0	50	415
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	25	0	0	50	0	0	25	0	0	0	0	0	0	25	75	0	0	0	575

Min1 – cogen – CC – Reduce Fossil, move up 1st coal + CT, move up 2nd coal

Min1 - cogen - CC - reduce fossil, move up 1st coal + CT, move up 2nd coal

Sheet Name = Min4

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	28	4	11	78	27	2	79	24	6	72	28	22	70	7	186	133	81	37	10	16	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.3%	1.4%	1.5%	1.6%	
Energy Efficiency (% of billable demand)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.4%	1.5%	1.6%	1.6%	
Egy Eff (MW + 15% for reserves)	1	2	4	7	10	13	16	20	23	27	31	35	39	43	47	51	55	60	64	69	
RPS Requirement (MWh) - Base N.L.	0	0	67,848	175,006	288,841	408,442	529,287	654,296	783,526	837,293	892,590	949,434	1,007,842	1,067,830	1,129,412	1,192,605	1,257,422	1,323,877	1,391,983	1,461,753	
RPS reduction from Energy Efficiency (MWh)	0	0	-95	-377	-875	-1,587	-2,519	-3,685	-5,095	-6,173	-7,356	-8,648	-10,052	-11,572	-13,213	-14,978	-16,871	-18,896	-21,058	-23,359	
Net RPS Requirement (MWh)	0	0	67,753	174,630	287,966	406,855	526,768	650,611	778,431	831,120	885,234	940,787	997,791	1,056,258	1,116,199	1,177,627	1,240,551	1,304,980	1,370,926	1,438,395	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.9%	41.8%	41.8%	41.8%	41.8%	41.7%	41.7%	41.7%	41.5%	41.5%	41.3%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	50	50	100	100	150	150	150	150	200	200	200	250	250	300	
Solar																					
Renewable Cogen (MW)																					
Accredited MW of new RPS wind	0	0	0	0	0	0	9	9	17	17	26	26	26	26	34	34	34	43	43	51	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil										-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen																					
150 MW CT													150	150	150	150	150	150	150	150	
New CC																					
New Coal or Nuclear																					
Coal-fired Cogen																					
Baseload Coal w/ 5% Biomass																					
New Baseload Coal										300	300	300	300	300	600	600	600	600	600	600	
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200	25			50			25			50							25	75	
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	143	0	0	0	0	300	0	0	0	0	0	600
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT	0	0	0	0	0	0	0	0	0	0	0	0	150	0	0	0	0	0	0	0	150
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	50	0	50	0	50	0	0	0	50	0	0	50	0	50	415
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	25	0	0	50	0	0	25	0	0	50	0	0	0	0	0	0	25	75	625

Min1 – wind – energy eff, move up CC & both coal

Min1 - wind - energy eff, move up CC & both coal

Sheet Name = Min5

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	27	22	22	122	67	14	104	46	15	171	116	56	-1	233	99	42	11	229	172	115	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Energy Efficiency (% of billable demand)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Egy Eff (MW + 15% for reserves)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
RPS Requirement (MWh) - Base N.L.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
RPS reduction from Energy Efficiency (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Net RPS Requirement (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar																					
Renewable Cogen (MW)																					
Accredited MW of new RPS wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil																					
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	
150 MW CT																					
New CC										237	237	237	237	237	237	237	237	237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen		10	20	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
Baseload Coal w/ 5% Biomass																					
New Baseload Coal														300	300	300	300	600	600	600	
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200				25			25								25				
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	50	50	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	300	0	0	0	300	0	0	757
NGCC	0	0	0	0	0	0	0	0	0	237	0	0	0	0	0	0	0	0	0	0	237
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	115
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	25	0	0	25	0	0	0	0	0	0	0	25	0	0	0	450

Moderate Regulation Scenario – Base Case

Moderate Regulation Scenario - Base Case

Sheet Name = Mod1

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	29	28	38	170	145	74	207	166	128	89	51	9	20	149	167	128	89	41	2	13	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.1%	0.2%	0.4%	0.6%	0.9%	1.1%	1.3%	1.5%	1.7%	1.9%	2.1%	2.3%	2.5%	2.7%	2.9%	3.1%	3.3%	3.4%	3.6%	3.8%	
Energy Efficiency (% of billable demand)	0.1%	0.2%	0.3%	0.6%	0.8%	1.0%	1.3%	1.5%	1.7%	1.9%	2.2%	2.4%	2.6%	2.8%	3.0%	3.2%	3.3%	3.5%	3.7%	3.9%	
Egy Eff (MW + 15% for reserves)	2	6	11	18	27	36	44	53	62	71	80	89	98	107	116	125	134	143	152	161	
RPS Requirement (MWh) - Base N.L.	0	0	135,697	280,010	433,262	594,098	756,125	923,712	1,096,937	1,275,875	1,460,602	1,651,190	1,763,724	1,879,380	1,998,191	2,120,186	2,245,396	2,373,848	2,505,570	2,640,587	
RPS reduction from Energy Efficiency (MWh)	0	0	-554	-1,725	-3,696	-6,406	-9,855	-14,065	-19,047	-24,811	-31,367	-38,725	-44,763	-51,229	-58,126	-65,460	-73,233	-81,450	-90,114	-99,229	
Net RPS Requirement (MWh)	0	0	135,142	278,286	429,566	587,692	746,269	909,646	1,077,889	1,251,064	1,429,235	1,612,465	1,718,961	1,828,151	1,940,065	2,054,727	2,172,163	2,292,399	2,415,456	2,541,357	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	37,230	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	111,690	111,690	111,690	111,690	111,690	111,690	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.8%	41.7%	41.5%	41.3%	41.1%	41.1%	41.1%	40.8%	40.5%	40.5%	40.1%	39.7%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	50	100	150	200	250	300	350	350	350	400	450	450	500	550	
Solar																					
Renewable Cogen (MW)			5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
Accredited MW of new RPS wind	0	0	0	0	0	0	9	17	26	34	43	51	60	60	60	68	77	77	85	94	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil															-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	20	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
150 MW CT																					
New CC														237	237	237	237	237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen		10	20	40	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
Baseload Coal w/ 5% Biomass															300	300	300	300	300	300	
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200											50							50	
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	50	55	35	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	0	143	0	0	0	0	0	300
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	237	0	0	0	0	0	0	237
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	50	50	50	50	50	50	50	0	0	50	50	0	50	50	665
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	50	475

Mod1 – cogen + CT & reduce CT

Mod1 - cogen + CT & reduce CT

Sheet Name = Mod2

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	29	8	91	188	143	81	213	173	134	96	57	15	18	156	174	126	87	48	8	11	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.1%	0.2%	0.4%	0.6%	0.9%	1.1%	1.3%	1.5%	1.7%	1.9%	2.1%	2.3%	2.5%	2.7%	2.9%	3.1%	3.3%	3.4%	3.6%	3.8%	
Energy Efficiency (% of billable demand)	0.1%	0.2%	0.3%	0.6%	0.8%	1.0%	1.3%	1.5%	1.7%	1.9%	2.2%	2.4%	2.6%	2.8%	3.0%	3.2%	3.3%	3.5%	3.7%	3.9%	
Egy Eff (MW + 15% for reserves)	2	6	11	18	27	36	44	53	62	71	80	89	98	107	116	125	134	143	152	161	
RPS Requirement (MWh) - Base N.L.	0	0	135,697	280,010	433,262	594,098	756,125	923,712	1,096,937	1,275,875	1,460,602	1,651,190	1,763,724	1,879,380	1,998,191	2,120,186	2,245,396	2,373,848	2,505,570	2,640,587	
RPS reduction from Energy Efficiency (MWh)	0	0	-554	-1,725	-3,696	-6,406	-9,855	-14,065	-19,047	-24,811	-31,367	-38,725	-44,763	-51,229	-58,126	-65,460	-73,233	-81,450	-90,114	-99,229	
Net RPS Requirement (MWh)	0	0	135,142	278,286	429,566	587,692	746,269	909,646	1,077,889	1,251,064	1,429,235	1,612,465	1,718,961	1,828,151	1,940,065	2,054,727	2,172,163	2,292,399	2,415,456	2,541,357	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	111,690	111,690	111,690	111,690	111,690	111,690	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.8%	41.7%	41.5%	41.3%	41.1%	41.1%	40.8%	40.8%	40.8%	40.5%	40.1%	39.7%	39.7%	
RPS MW based on wind not in R.T.	0	0	0	0	0	50	100	150	200	250	300	350	350	400	400	400	450	500	550	550	
Solar																					
Renewable Cogen (MW)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Accredited MW of new RPS wind	0	0	0	0	0	9	17	26	34	43	51	60	60	68	68	68	77	85	94	94	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil															-157	-157	-157	-157	-157	-157	
Reduce Existing CT			-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	
Gas-Fired Generation																					
Gas-fired Cogen		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
150 MW CT			150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	
New CC														237	237	237	237	237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Baseload Coal w/ 5% Biomass															300	300	300	300	300	300	
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200											50							50	
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	0	143	0	0	0	0	0	300
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	237	0	0	0	0	0	0	237
CT	0	0	98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	98
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	50	50	50	50	50	50	50	0	50	0	0	50	50	50	0	665
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	50	475

Mod1 – gas cogen – 20 MW coal cogen +1/4 pumped storage – CC

Mod1 - gas cogen - 20 MW coal cogen + 1/4 pumped storage - CC

Sheet Name = Mod3

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	29	18	18	140	95	24	157	116	78	39	1	293	254	196	214	175	136	88	49	10	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.1%	0.2%	0.4%	0.6%	0.9%	1.1%	1.3%	1.5%	1.7%	1.9%	2.1%	2.3%	2.5%	2.7%	2.9%	3.1%	3.3%	3.4%	3.6%	3.8%	
Energy Efficiency (% of billable demand)	0.1%	0.2%	0.3%	0.6%	0.8%	1.0%	1.3%	1.5%	1.7%	1.9%	2.2%	2.4%	2.6%	2.8%	3.0%	3.2%	3.3%	3.5%	3.7%	3.9%	
Egy Eff (MW + 15% for reserves)	2	6	11	18	27	36	44	53	62	71	80	89	98	107	116	125	134	143	152	161	
RPS Requirement (MWh) - Base N.L.	0	0	135,697	280,010	433,262	594,098	756,125	923,712	1,096,937	1,275,875	1,460,602	1,651,190	1,763,724	1,879,380	1,998,191	2,120,186	2,245,396	2,373,848	2,505,570	2,640,587	
RPS reduction from Energy Efficiency (MWh)	0	0	-554	-1,725	-3,696	-6,406	-9,855	-14,065	-19,047	-24,811	-31,367	-38,725	-44,763	-51,229	-58,126	-65,460	-73,233	-81,450	-90,114	-99,229	
Net RPS Requirement (MWh)	0	0	135,142	278,286	429,566	587,692	746,269	909,646	1,077,889	1,251,064	1,429,235	1,612,465	1,718,961	1,828,151	1,940,065	2,054,727	2,172,163	2,292,399	2,415,456	2,541,357	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	37,230	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	111,690	111,690	111,690	111,690	111,690	111,690	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.8%	41.7%	41.5%	41.3%	41.1%	41.1%	41.1%	40.8%	40.5%	40.5%	40.1%	39.7%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	50	100	150	200	250	300	350	350	350	400	450	450	500	550	
Solar																					
Renewable Cogen (MW)			5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
Accredited MW of new RPS wind	0	0	0	0	0	0	9	17	26	34	43	51	60	60	60	68	77	77	85	94	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil															-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
150 MW CT																					
New CC														0	0	0	0	0	0	0	
New Coal or Nuclear																					
Coal-fired Cogen		10	20	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
Baseload Coal w/ 5% Biomass															300	300	300	300	300	300	
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200																			
Pumped Storage												334	334	334	334	334	334	334	334	334	
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	40	45	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	0	143	0	0	0	0	0	300
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	50	50	50	50	50	50	50	0	0	50	50	0	50	50	665
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	334	0	0	0	0	0	0	0	0	334
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	375

Mod1 -with high energy eff, delay CC & coal

Moderate Regulation Scenario - Mod1 with high energy eff, delay CC & coal

Sheet Name = Mod4

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	30	32	44	181	164	103	246	216	189	163	137	107	74	39	17	34	252	229	198	176	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.2%	0.4%	0.6%	1.0%	1.4%	1.9%	2.4%	2.9%	3.4%	3.9%	4.4%	4.9%	5.4%	5.9%	6.4%	6.9%	7.4%	7.9%	8.4%	8.9%	
Energy Efficiency (% of billable demand)	0.1%	0.3%	0.5%	0.9%	1.4%	1.9%	2.4%	2.9%	3.4%	4.0%	4.5%	5.0%	5.5%	6.0%	6.6%	7.1%	7.6%	8.1%	8.6%	9.2%	
Egy Eff (MW + 15% for reserves)	3	11	17	29	46	64	84	103	124	144	166	188	210	233	257	281	306	331	356	383	
RPS Requirement (MWh) - Base N.L.	0	0	135,697	280,010	433,262	594,098	756,125	923,712	1,096,937	1,275,875	1,460,602	1,651,190	1,763,724	1,879,380	1,998,191	2,120,186	2,245,396	2,373,848	2,505,570	2,640,587	
RPS reduction from Energy Efficiency (MWh)	0	0	-814	-2,660	-6,066	-11,288	-18,147	-26,788	-37,296	-49,759	-64,266	-80,908	-95,241	-110,883	-127,884	-146,293	-166,159	-187,534	-210,468	-235,012	
Net RPS Requirement (MWh)	0	0	134,882	277,350	427,196	582,810	737,978	896,924	1,059,641	1,226,116	1,396,336	1,570,282	1,668,483	1,768,497	1,870,307	1,973,893	2,079,237	2,186,314	2,295,102	2,405,574	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	37,230	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	111,690	111,690	111,690	111,690	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.8%	41.7%	41.5%	41.3%	41.3%	41.1%	40.8%	40.8%	40.8%	40.5%	40.5%	40.1%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	50	100	150	200	250	300	300	350	400	400	400	450	450	500	
Solar																					
Renewable Cogen (MW)			5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
Accredited MW of new RPS wind	0	0	0	0	0	0	9	17	26	34	43	51	51	60	68	68	68	77	77	85	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil															-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	20	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
150 MW CT																					
New CC															237	237	237	237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen		10	20	40	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
Baseload Coal w/ 5% Biomass																	300	300	300	300	
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200														50					
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	50	55	35	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	0	-157	0	300	0	0	0	300
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	237	0	0	0	0	0	237
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	50	50	50	50	50	50	0	50	50	0	0	50	0	50	615
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	425

Mod1 with high energy eff & no reduce fossil – new coal, delay CC

Moderate Regulation Scenario - Mod1 with high energy eff & no reduce fossil - new coal, delay CC

Sheet Name = Mod5

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	30	32	44	181	164	103	246	216	189	163	137	107	74	39	174	141	118	86	63	41	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.2%	0.4%	0.6%	1.0%	1.4%	1.9%	2.4%	2.9%	3.4%	3.9%	4.4%	4.9%	5.4%	5.9%	6.4%	6.9%	7.4%	7.9%	8.4%	8.9%	
Energy Efficiency (% of billable demand)	0.1%	0.3%	0.5%	0.9%	1.4%	1.9%	2.4%	2.9%	3.4%	4.0%	4.5%	5.0%	5.5%	6.0%	6.6%	7.1%	7.6%	8.1%	8.6%	9.2%	
Egy Eff (MW + 15% for reserves)	3	11	17	29	46	64	84	103	124	144	166	188	210	233	257	281	306	331	356	383	
RPS Requirement (MWh) - Base N.L.	0	0	135,697	280,010	433,262	594,098	756,125	923,712	1,096,937	1,275,875	1,460,602	1,651,190	1,763,724	1,879,380	1,998,191	2,120,186	2,245,396	2,373,848	2,505,570	2,640,587	
RPS reduction from Energy Efficiency (MWh)	0	0	-814	-2,660	-6,066	-11,288	-18,147	-26,788	-37,296	-49,759	-64,266	-80,908	-95,241	-110,883	-127,884	-146,293	-166,159	-187,534	-210,468	-235,012	
Net RPS Requirement (MWh)	0	0	134,882	277,350	427,196	582,810	737,978	896,924	1,059,641	1,226,116	1,396,336	1,570,282	1,668,483	1,768,497	1,870,307	1,973,893	2,079,237	2,186,314	2,295,102	2,405,574	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	37,230	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.8%	41.7%	41.5%	41.3%	41.3%	41.1%	40.8%	40.8%	40.5%	40.5%	40.1%	39.7%	
RPS MW based on wind not in R.T.	0	0	0	0	0	0	50	100	150	200	250	300	300	350	400	400	450	450	500	550	
Solar																					
Renewable Cogen (MW)			5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
Accredited MW of new RPS wind	0	0	0	0	0	0	9	17	26	34	43	51	51	60	68	68	77	77	85	94	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil																					
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	20	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
150 MW CT																					
New CC															237	237	237	237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen		10	20	40	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
Baseload Coal w/ 5% Biomass																					
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200																			
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	50	55	35	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	157
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	237	0	0	0	0	0	237
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	0	50	50	50	50	50	50	0	50	50	0	50	0	50	50	665
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	375

Mod1 – energy efficiency + CT, Move up CC

Moderate Regulation Scenario - Mod1 - energy efficiency + CT, Move up CC

Sheet Name = Mod6

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	27	22	27	152	117	47	162	113	66	18	21	-5	109	51	60	3	5	57	8	10	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Energy Efficiency (% of billable demand)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Egy Eff (MW + 15% for reserves)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
RPS Requirement (MWh) - Base N.L.	0	0	135,697	280,010	433,262	594,098	756,125	923,712	1,096,937	1,275,875	1,460,602	1,651,190	1,763,724	1,879,380	1,998,191	2,120,186	2,245,396	2,373,848	2,505,570	2,640,587	
RPS reduction from Energy Efficiency (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Net RPS Requirement (MWh)	0	0	135,697	280,010	433,262	594,098	756,125	923,712	1,096,937	1,275,875	1,460,602	1,651,190	1,763,724	1,879,380	1,998,191	2,120,186	2,245,396	2,373,848	2,505,570	2,640,587	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	37,230	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	111,690	111,690	111,690	111,690	111,690	111,690	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.8%	41.7%	41.5%	41.3%	41.1%	40.8%	40.8%	40.8%	40.5%	40.1%	39.7%	39.3%	
RPS MW based on wind not in R.T.	0	0	0	0	0	50	50	100	150	200	250	300	350	400	400	400	450	500	550	600	
Solar																					
Renewable Cogen (MW)			5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
Accredited MW of new RPS wind	0	0	0	0	0	9	9	17	26	34	43	51	60	68	68	68	77	85	94	102	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil															-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	20	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
150 MW CT																		150	150	150	
New CC													237	237	237	237	237	237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen		10	20	40	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
Baseload Coal w/ 5% Biomass															300	300	300	300	300	300	
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200									50	75					50			50	
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	50	55	35	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	0	143	0	0	0	0	0	300
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	237	0	0	0	0	0	0	0	237
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	0	0	150
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	50	0	50	50	50	50	50	50	50	0	0	50	50	50	50	715
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	50	75	0	0	0	0	50	0	0	50	600

Mod1 – with low energy efficiency + CT, Move up CC

Moderate Regulation Scenario - Mod1 with low energy eff + CT, Move up CC

Sheet Name = Mod7

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	28	24	31	158	127	60	179	133	89	46	2	4	148	94	107	54	10	16	73	20	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.3%	1.4%	1.5%	1.6%	
Energy Efficiency (% of billable demand)	0.0%	0.1%	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.4%	1.5%	1.6%	1.6%	
Egy Eff (MW + 15% for reserves)	1	2	4	7	10	13	16	20	23	27	31	35	39	43	47	51	55	60	64	69	
RPS Requirement (MWh) - Base N.L.	0	0	135,697	280,010	433,262	594,098	756,125	923,712	1,096,937	1,275,875	1,460,602	1,651,190	1,763,724	1,879,380	1,998,191	2,120,186	2,245,396	2,373,848	2,505,570	2,640,587	
RPS reduction from Energy Efficiency (MWh)	0	0	-191	-603	-1,313	-2,308	-3,598	-5,202	-7,133	-9,407	-12,037	-15,039	-17,590	-20,367	-23,377	-26,628	-30,127	-33,883	-37,904	-42,196	
Net RPS Requirement (MWh)	0	0	135,506	279,407	431,949	591,790	752,526	918,510	1,089,803	1,266,468	1,448,565	1,636,151	1,746,134	1,859,013	1,974,814	2,093,559	2,215,269	2,339,965	2,467,666	2,598,390	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	37,230	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	74,460	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	111,690	111,690	111,690	111,690	111,690	111,690	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	42.0%	41.9%	41.8%	41.7%	41.5%	41.3%	41.1%	40.8%	40.8%	40.8%	40.5%	40.1%	39.7%	39.7%	
RPS MW based on wind not in R.T.	0	0	0	0	0	50	50	100	150	200	250	300	350	400	400	400	450	500	550	550	
Solar																					
Renewable Cogen (MW)			5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
Accredited MW of new RPS wind	0	0	0	0	0	9	9	17	26	34	43	51	60	68	68	68	77	85	94	94	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil															-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	20	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
150 MW CT																			150	150	
New CC													237	237	237	237	237	237	237	237	
New Coal or Nuclear																					
Coal-fired Cogen		10	20	40	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
Baseload Coal w/ 5% Biomass															300	300	300	300	300	300	
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200										50						50			
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	50	55	35	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	0	0	0	0	0	0	0	143	0	0	0	0	0	300
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	237	0	0	0	0	0	0	0	237
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	0	150
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	0	50	0	50	50	50	50	50	50	50	0	0	50	50	50	0	665
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	50	0	0	475

Extreme Regulation Scenario – Base Case

Extreme Regulation Scenario - Base Case

Sheet Name = Ext1

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	30	32	64	211	222	179	321	143	125	107	89	68	52	34	340	333	327	321	289	259	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.2%	0.4%	0.6%	1.0%	1.4%	1.9%	2.4%	2.9%	3.4%	3.9%	4.4%	4.9%	5.4%	5.9%	6.4%	6.9%	7.4%	7.9%	8.4%	8.9%	
Energy Efficiency (% of billable demand)	0.1%	0.3%	0.5%	0.9%	1.4%	1.9%	2.4%	2.9%	3.4%	4.0%	4.5%	5.0%	5.5%	6.0%	6.6%	7.1%	7.6%	8.1%	8.6%	9.2%	
Egy Eff (MW + 15% for reserves)	3	11	17	29	46	64	84	103	124	144	166	188	210	233	257	281	306	331	356	383	
RPS Requirement (MWh) - Base N.L.	0	0	203,545	476,018	765,430	1,069,376	1,376,147	1,693,471	2,021,497	2,360,369	2,710,228	3,071,214	3,443,461	3,827,102	4,222,264	4,629,074	5,047,650	5,478,111	5,567,933	5,658,400	
RPS reduction from Energy Efficiency (MWh)	0	0	-1,221	-4,522	-10,716	-20,318	-33,028	-49,111	-68,731	-92,054	-119,250	-150,489	-185,947	-225,799	-270,225	-319,406	-373,526	-432,771	-467,706	-503,598	
Net RPS Requirement (MWh)	0	0	202,324	471,495	754,714	1,049,058	1,343,119	1,644,361	1,952,766	2,268,315	2,590,978	2,920,725	3,257,514	3,601,303	3,952,039	4,309,667	4,674,124	5,045,340	5,100,226	5,154,802	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	111,690	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	41.8%	41.7%	41.3%	40.8%	40.5%	39.7%	38.9%	37.8%	37.1%	36.2%	35.7%	35.0%	34.4%	34.2%	34.2%	
RPS MW based on wind not in R.T.	0	0	0	0	50	150	200	300	400	500	600	700	800	950	1,050	1,200	1,350	1,500	1,500	1,500	
Solar																					
Renewable Cogen (MW)			15	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	
Accredited MW of new RPS wind	0	0	0	0	9	26	34	51	68	85	102	119	136	162	179	204	230	255	255	255	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil								-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	30	50	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	
150 MW CT																					
New CC																					
New Coal or Nuclear																					
Coal-fired Cogen		10	20	40	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
Baseload Coal w/ 5% Biomass																					
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear															400	400	400	400	400	400	
Other																					
Capacity Purchase	175	200																			
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	50	75	45	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	-157	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	400	0	0	0	0	0	400
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	50	100	50	100	100	100	100	100	100	150	100	150	150	150	0	0	1,615
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	375

Ext1 – coal cogen + ½ pumped storage – nuclear

Ext1 - coal cogen + 1/2 pump storage - nuclear

Sheet Name = Ext2

Final Surplus/Deficit	30	22	44	171	162	119	261	83	65	47	29	676	660	642	548	541	535	529	497	467	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.2%	0.4%	0.6%	1.0%	1.4%	1.9%	2.4%	2.9%	3.4%	3.9%	4.4%	4.9%	5.4%	5.9%	6.4%	6.9%	7.4%	7.9%	8.4%	8.9%	
Energy Efficiency (% of billable demand)	0.1%	0.3%	0.5%	0.9%	1.4%	1.9%	2.4%	2.9%	3.4%	4.0%	4.5%	5.0%	5.5%	6.0%	6.6%	7.1%	7.6%	8.1%	8.6%	9.2%	
Egy Eff (MW + 15% for reserves)	3	11	17	29	46	64	84	103	124	144	166	188	210	233	257	281	306	331	356	383	
RPS Requirement (MWh) - Base N.L.	0	0	203,545	476,018	765,430	1,069,376	1,376,147	1,693,471	2,021,497	2,360,369	2,710,228	3,071,214	3,443,461	3,827,102	4,222,264	4,629,074	5,047,650	5,478,111	5,567,933	5,658,400	
RPS reduction from Energy Efficiency (MWh)	0	0	-1,221	-4,522	-10,716	-20,318	-33,028	-49,111	-68,731	-92,054	-119,250	-150,489	-185,947	-225,799	-270,225	-319,406	-373,526	-432,771	-467,706	-503,598	
Net RPS Requirement (MWh)	0	0	202,324	471,495	754,714	1,049,058	1,343,119	1,644,361	1,952,766	2,268,315	2,590,978	2,920,725	3,257,514	3,601,303	3,952,039	4,309,667	4,674,124	5,045,340	5,100,226	5,154,802	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	111,690	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	41.8%	41.7%	41.3%	40.8%	40.5%	39.7%	38.9%	37.8%	37.1%	36.2%	35.7%	35.0%	34.4%	34.2%	34.2%	
RPS MW based on wind not in R.T.	0	0	0	0	50	150	200	300	400	500	600	700	800	950	1,050	1,200	1,350	1,500	1,500	1,500	
Solar																					
Renewable Cogen (MW)			15	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	
Accredited MW of new RPS wind	0	0	0	0	9	26	34	51	68	85	102	119	136	162	179	204	230	255	255	255	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil								-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	30	50	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	
150 MW CT																					
New CC																					
New Coal or Nuclear																					
Coal-fired Cogen																					
Baseload Coal w/ 5% Biomass																					
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	200																			
Pumped Storage												668	668	668	668	668	668	668	668	668	
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	40	65	25	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	-157	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	50	100	50	100	100	100	100	100	100	150	100	150	150	150	0	0	1,615
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	668	0	0	0	0	0	0	0	0	668
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	375

Ext1 + 3 CT = coal cogen – existing CT – nuclear

Ext1 + 3 CT - coal cogen - existing CT- nuclear

Sheet Name = Ext3

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	30	22	142	269	260	217	359	181	163	145	127	106	90	72	128	121	115	109	77	197	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.2%	0.4%	0.6%	1.0%	1.4%	1.9%	2.4%	2.9%	3.4%	3.9%	4.4%	4.9%	5.4%	5.9%	6.4%	6.9%	7.4%	7.9%	8.4%	8.9%	
Energy Efficiency (% of billable demand)	0.1%	0.3%	0.5%	0.9%	1.4%	1.9%	2.4%	2.9%	3.4%	4.0%	4.5%	5.0%	5.5%	6.0%	6.6%	7.1%	7.6%	8.1%	8.6%	9.2%	
Egy Eff (MW + 15% for reserves)	3	11	17	29	46	64	84	103	124	144	166	188	210	233	257	281	306	331	356	383	
RPS Requirement (MWh) - Base N.L.	0	0	203,545	476,018	765,430	1,069,376	1,376,147	1,693,471	2,021,497	2,360,369	2,710,228	3,071,214	3,443,461	3,827,102	4,222,264	4,629,074	5,047,650	5,478,111	5,567,933	5,658,400	
RPS reduction from Energy Efficiency (MWh)	0	0	-1,221	-4,522	-10,716	-20,318	-33,028	-49,111	-68,731	-92,054	-119,250	-150,489	-185,947	-225,799	-270,225	-319,406	-373,526	-432,771	-467,706	-503,598	
Net RPS Requirement (MWh)	0	0	202,324	471,495	754,714	1,049,058	1,343,119	1,644,361	1,952,766	2,268,315	2,590,978	2,920,725	3,257,514	3,601,303	3,952,039	4,309,667	4,674,124	5,045,340	5,100,226	5,154,802	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Renewable Cogen (MWh at 85% C.F.)	0	0	111,690	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	41.8%	41.7%	41.3%	40.8%	40.5%	39.7%	38.9%	37.8%	37.1%	36.2%	35.7%	35.0%	34.4%	34.2%	34.2%	
RPS MW based on wind not in R.T.	0	0	0	0	50	150	200	300	400	500	600	700	800	950	1,050	1,200	1,350	1,500	1,500	1,500	
Solar																					
Renewable Cogen (MW)			15	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	
Accredited MW of new RPS wind	0	0	0	0	9	26	34	51	68	85	102	119	136	162	179	204	230	255	255	255	
Biomass Plant																					
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil								-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	
Reduce Existing CT			-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	-52	
Gas-Fired Generation																					
Gas-fired Cogen		10	30	50	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	
150 MW CT		150	150	150	150	150	150	150	150	150	150	150	150	150	300	300	300	300	300	450	
New CC																					
New Coal or Nuclear																					
Coal-fired Cogen																					
Baseload Coal w/ 5% Biomass																					
New Baseload Coal																					
New Coal w/ carbon capture																					
New Nuclear																					
Other																					
Capacity Purchase	175	50																			
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	40	65	25	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	-157	0	0	0	0	0	0	0	0	0	0	0	0	0
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT	0	150	-52	0	0	0	0	0	0	0	0	0	0	0	150	0	0	0	0	150	398
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	50	100	50	100	100	100	100	100	100	150	100	150	150	150	0	0	1,615
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 yr Capacity Purchases	175	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	225

Ext1 – coal cogen + biomass + solar – nuclear + coal w/carbon capture

Ext1 - coal cogen + biomass + solar - nuclear + coal w/ carbon capture

Sheet Name = Ext4

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Final Surplus/Deficit	30	22	44	171	162	119	261	83	65	47	29	66	51	24	239	224	235	239	234	221	
Native Load - Normal Weather	2,508	2,702	2,783	2,852	2,929	2,992	3,037	3,082	3,127	3,172	3,217	3,263	3,308	3,354	3,400	3,446	3,492	3,537	3,583	3,629	
Surplus/Deficit based on High Weather	-148	-228	-78	-18	-112	-190	-75	-133	-189	-245	-300	-360	-417	-483	-617	-673	-730	-787	-844	-901	
Renewables & Energy Efficiency																					
Energy Efficiency (% of energy)	0.2%	0.4%	0.6%	1.0%	1.4%	1.9%	2.4%	2.9%	3.4%	3.9%	4.4%	4.9%	5.4%	5.9%	6.4%	6.9%	7.4%	7.9%	8.4%	8.9%	
Energy Efficiency (% of billable demand)	0.1%	0.3%	0.5%	0.9%	1.4%	1.9%	2.4%	2.9%	3.4%	4.0%	4.5%	5.0%	5.5%	6.0%	6.6%	7.1%	7.6%	8.1%	8.6%	9.2%	
Egy Eff (MW + 15% for reserves)	3	11	17	29	46	64	84	103	124	144	166	188	210	233	257	281	306	331	356	383	
RPS Requirement (MWh) - Base N.L.	0	0	203,545	476,018	765,430	1,069,376	1,376,147	1,693,471	2,021,497	2,360,369	2,710,228	3,071,214	3,443,461	3,827,102	4,222,264	4,629,074	5,047,650	5,478,111	5,567,933	5,658,400	
RPS reduction from Energy Efficiency (MWh)	0	0	-1,221	-4,522	-10,716	-20,318	-33,028	-49,111	-68,731	-92,054	-119,250	-150,489	-185,947	-225,799	-270,225	-319,406	-373,526	-432,771	-467,706	-503,598	
Net RPS Requirement (MWh)	0	0	202,324	471,495	754,714	1,049,058	1,343,119	1,644,361	1,952,766	2,268,315	2,590,978	2,920,725	3,257,514	3,601,303	3,952,039	4,309,667	4,674,124	5,045,340	5,100,226	5,154,802	
Wind in Rate Track (MWh)	112,775	112,775	220,336	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	517,051	
Biomass Plant (MWh @ 85% CF)	0	0	0	0	0	0	0	0	0	0	0	558,450	558,450	558,450	558,450	558,450	558,450	558,450	558,450	558,450	
Solar (MWh @ 20% CF)	0	0	0	0	0	0	0	0	0	0	0	0	35,040	35,040	35,040	35,040	70,080	105,120	140,160	175,200	
Renewable Cogen (MWh at 85% C.F.)	0	0	111,690	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	148,920	
Biomass cofiring w/ Coal (MWh - 5%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cummulative Capacity Factor for wind not in RT	42.0%	42.0%	42.0%	42.0%	42.0%	41.8%	41.7%	41.3%	40.8%	40.5%	39.7%	40.1%	39.3%	38.5%	37.8%	36.8%	36.2%	35.4%	35.2%	35.2%	
RPS MW based on wind not in R.T.	0	0	0	0	50	150	200	300	400	500	600	600	600	700	850	950	1,100	1,200	1,250	1,250	
Solar													20	20	20	20	40	60	80	100	
Renewable Cogen (MW)			15	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	
Accredited MW of new RPS wind	0	0	0	0	9	26	34	51	68	85	102	102	102	119	145	162	187	204	213	213	
Biomass Plant												75	75	75	75	75	75	75	75	75	
Accredited MW of solar (90% nameplate)	0	0	0	0	0	0	0	0	0	0	0	0	18	18	18	18	36	54	72	90	
Additional Resources in Rate Track																					
Cogen		30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
CNS - HP Turbine Uprate				10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
15 MW AWEF (17% of nameplate)				3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
100 MW New Wind Facility (17%)				17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
Existing Units																					
CNS Stretch Update (5%)					39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	
Reduce Fossil								-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	-157	
Reduce Existing CT																					
Gas-Fired Generation																					
Gas-fired Cogen		10	30	50	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	
150 MW CT																					
New CC																					
New Coal or Nuclear																					
Coal-fired Cogen																					
Baseload Coal w/ 5% Biomass																					
New Baseload Coal																					
New Coal w/ carbon capture (w/ participants)															300	300	300	300	300	300	
New Nuclear																					
Other																					
Capacity Purchase	175	200																			
Pumped Storage																					
Resource																					
Resource																					
Summary of Annual Additions																					
CNS Uprate (App K hard-coded)	11	0	0	10	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Cogen	0	40	65	25	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150
Coal (NC2 hard-coded)	0	157	0	0	0	0	0	-157	0	0	0	0	0	0	300	0	0	0	0	0	300
NGCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind (15 AWEF & 100 new hard-coded)	0	0	0	115	50	100	50	100	100	100	100	0	0	100	150	100	150	100	50	0	1,365
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	20	20	20	20	100
Biomass Plant	0	0	0	0	0	0	0	0	0	0	0	75	0	0	0	0	0	0	0	0	75
1 yr Capacity Purchases	175	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	375

Appendix E – Summit Blue Report

NEBRASKA PUBLIC POWER DISTRICT
DSM POTENTIAL STUDY AND PLAN

Submitted To:

Nebraska Public Power District

November 6, 2007

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Appendix A: 2006 DSM Results by State A-1

Appendix B: Electric Price Escalators and Nominal Costs B-1

EXECUTIVE SUMMARY

This section of the report provides a high-level overview of the project methodology and results.

Introduction and Overall Methodology

Nebraska Public Power District (NPPD) hired Summit Blue Consulting (Summit Blue) in April 2007 to conduct a demand side management potential study and plan for upcoming IRP.

Study Strategy and Tactics

The overall strategy and tactics for the DSM potential study are as follows:

- Conduct project initiation meeting with NPPD staff.
- Conduct a Midwest-focused DSM benchmarking and best practices analysis.
- Develop baseline consumption profiles and initial building simulation model specifications.
- Characterize DSM measures that are appropriate for NPPD's service area.
- Conduct benefit-cost analysis.
- Estimate DSM potentials for the 2008-2028 period for residential and commercial customers using a spreadsheet model.
- Develop DSM program plans.

DSM Benchmarking and Best Practices Assessment

Data and information were collected for 2006 DSM program results for eleven utilities and energy agencies in the Midwest. This analysis of DSM program results normalized the reported total program results for utility or agency size and sales to major customer class.

The achievement of significant DSM savings is influenced by several factors, including the regulatory environment under which utilities and agencies operate, whether DSM funds are provided through systems benefits charges, how the issue of lost revenues is addressed, the provision of financial incentives for DSM performance, etc. Iowa and Minnesota achieved about 1% reduction in annual energy sales due to DSM programs in 2006.

All states achieving high DSM savings either set significant mandated goals for utilities' DSM programs or use public benefits funds to implement DSM programs. Other success factors include financial incentives for cost-effective DSM (Minnesota), adjustments for lost revenues caused by DSM programs, and use of the TRC test or societal test for cost-effectiveness rather than the RIM test (Iowa and Minnesota).

1 shows the median results for DSM spending, savings, and costs overall for the C&I customer sector for all organizations.

Table E-1. Medians for Overall Results

Spending	Energy Savings	Demand Savings	Cost of Energy	Cost of Savings	
as % of Revenue	as % of Sales	as % of Peak Demand	$/kWh	$/kWh	$/kW
1.3%	0.6%	0.9%	$0.07	$0.15	$595

Interstate P&L (MN) has the highest spending rates at 2.8% of revenues. MidAmerican (IA), Great River Energy, Interstate P&L (IA), and Xcel have high DSM spending as a percentage of revenue at 1.8% - 2.0% of revenues.

Interstate P&L (MN) also has the highest energy savings as a percentage of sales at about 1.6% of sales. Minnesota Power achieved the lowest cost of energy savings at $0.08 per first year kWh saved.

NPPD has the highest demand savings as a percent of peak demand at 2.9% of peak demand. Xcel, Interstate P&L (MN), and MidAmerican (IA) have high demand savings as a percent of peak demand at 1.1% - 1.6% of baseline peak demands. NPPD also has the lowest costs of conserved demand at $33/kW. Duke Energy Indiana, Xcel, and MidAmerican (IA) have low costs of conserved demand at $265/kW - $531/kW.

The scatter plots below portray the utility energy savings and costs of conserved energy and the peak demand savings and costs of demand savings graphically.

Figure E-1. Scatter Plot of Energy Savings and First Year Costs ($/kWh)

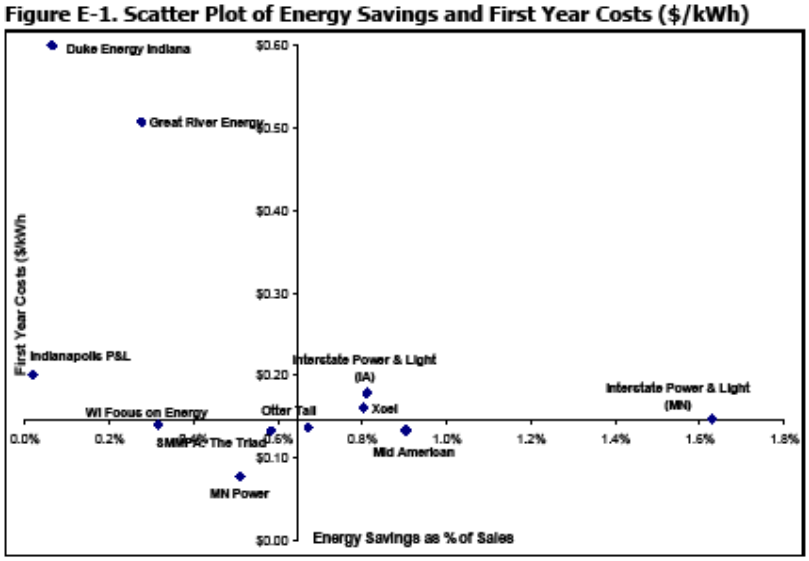
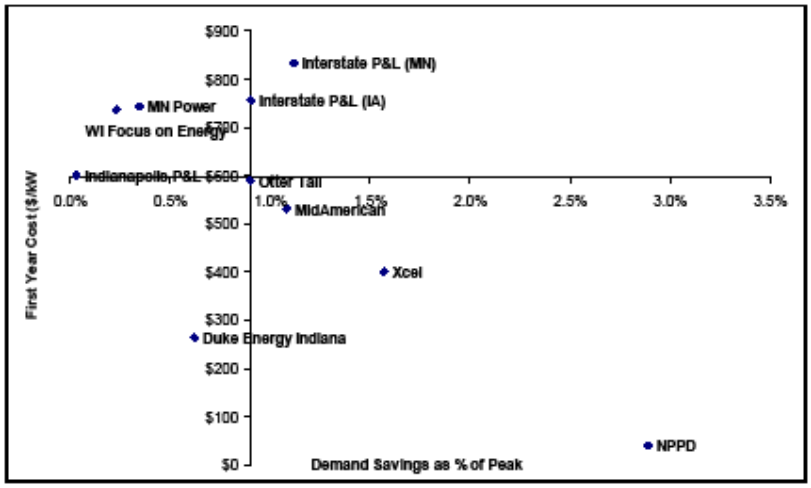


Figure E-2. Scatter Plot of Demand Savings and First Year Costs ($/kW)



Baseline Energy Consumption Profiles

NPPD supplied considerable input data for this task including customer counts and billing data by market segment and sales forecasts for the Company's customer sectors. Other NPPD data sources include results of NPPD's 2006 residential appliance saturation survey, summaries of its 2007 irrigation energy source survey, and its 2006 irrigation and load management survey, which Summit Blue used to characterize NPPD's customers. Table E-2 below shows end use consumption estimates by customer sector.

Table E-2. Nebraska Public Power District Summary 2006 Customer Statistics[1]

	Residential	Irrigation	Commercial & Government	Industrial
Customers	253,094	35,085	51,340	390
Energy Sales (GWh)	3,542	866	3,656	2,318
Average Energy Use/Customer (kWh)	13,995	24,669	71,207	5,942,479
Demand (MW)	767	511	830	383
Average kW/Customer	3.0	14.6	16.2	983.1

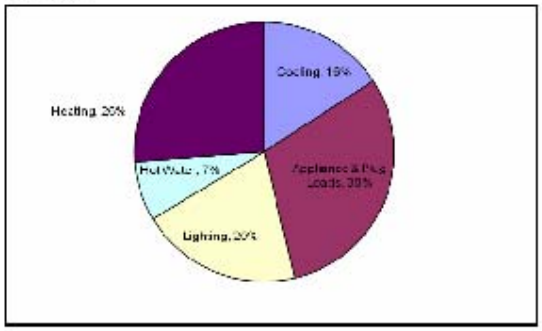
Summit Blue modeled two baseline homes to represent the residential sector: new single family and existing single family. The appliance saturation survey data were used to determine basic home characteristics for the models. The models were executed with the Energy-10 simulation software

[1] Data for other customer sectors (seasonal, street lights, and towns served by NPPD wholesale customers) account for about 4% of total energy sales and 2% of total peak demand.

distributed by the Sustainable Buildings Industries Council. To enhance the applicability of the models to NPPD customers, Summit Blue used an Omaha, Nebraska weather data set for all simulations, incorporated NPPD's appliance saturation survey data, and calibrated the simulations to averages of 2004-2006 consumption data of randomly selected customers.[2]

About 32% of NPPD residences have electric heat and 48% have electric hot water; therefore, the overall residential sector electric consumption profile looks like Figure E-3.

Figure E-3. Residential Electric Consumption Profile – All Heat and Hot Water Energy Sources

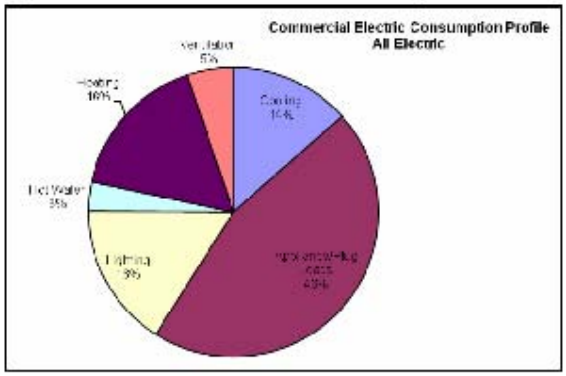


In order to estimate the savings for climate-dependent or interactive measures for NPPD's commercial and government customers, Summit Blue created a basic building simulation model using eQUEST v. 3.6 to represent the small office segment. This segment was used as a proxy for the Commercial, Industrial, and Government sectors.

[2] Energy-10 is a well-respected hourly simulation tool specifically designed for smaller buildings (less than 10,000 square feet) with pre-programmed default values for residential applications to ensure consistency among model runs.

The following pie chart shows the electric consumption profiles for all-electric heating small office commercial buildings:

Figure E-4. Commercial Electric Consumption Profile - All Electric



Most of Nebraska Public Power District's system load, 70%, is for its wholesale customers. Irrigation loads are among the most significant type in the NPPD service territory. In 2006 the peak system load was 2,671 MW, and during the same year the connected irrigation load was estimated as 1,380 MW[3] with more than 1.5[4] million horsepower of electric motors. This equipment contributes between 400 and 500 MW to the system peak.[5]

DSM Measure Characterization and Benefit-Cost Analysis Results

Summit Blue evaluated 43 residential measures and 24 commercial DSM measures for possible inclusion in NPPD's DSM portfolio. Representative and common examples of each technology type, such as compact fluorescent lamps, were analyzed.

Residential measures were analyzed for two market segments: new single family and existing single family. Impacts for weather dependent measures such as HVAC were estimated using the Energy-10 building simulation model. For measures that are weather independent, engineering estimates and reputable published sources such as the California DEER database were used.

Levelized avoided costs were calculated on the basis of nominal avoided costs provided by NPPD.

The number of residential measures for each end use in this evaluation are as follows:

[3] *Load Management, Energy Efficiency and Conservation*, NPPD, 2007, p. 11.

[4] *Ibid*. p. 5.

[5] *Summary Report of the NPPD 2004 Irrigation Energy Source Survey*, prepared by NPPD Corporate Planning and Risk, December 2004, p. 4.

- 7 lighting energy efficiency measures
- 13 cooling and heating energy efficiency measures
- 9 building envelope energy efficiency measures (for each cooling/heating type)
- 7 refrigeration and appliance energy efficiency measures
- 11 water heating energy efficiency measures
- 2 demand response measures

The number of commercial measures for each end use in this evaluation are as follows:

- 9 lighting energy efficiency measures (for two heating types)
- 5 cooling/heating/fan motors energy efficiency measures
- 3 water heating energy efficiency measures
- 3 custom energy efficiency measures
- 3 demand response measures

The measures were evaluated with respect to each of the four main California stakeholder tests.

1. Participant test: measures are cost effective from this perspective if the reduced electric costs to the participating customer from the measure exceed the after-rebate cost of the measure to the customer.
2. The utility test (UT): measures are cost effective from this perspective if the costs avoided by the measures' energy and demand savings are greater than the utility DSM program costs to promote the measure, including customer rebates.
3. Rate impact (RIM) test: measures are cost effective from this perspective if their avoided costs are greater than the sum of the DSM program costs and the "lost revenues" caused by the measure.
4. The total resource cost (TRC) test: measures are cost effective from this perspective if their avoided costs are greater than the sum of the measure costs and the DSM program administrative costs.

In line with standard industry practice, Summit Blue used the TRC test to determine which DSM programs to include in NPPD's portfolio of DSM programs. The RIM test is a more restrictive test that is only used as the main DSM benefit-cost test in very few states.[6] Almost all commercial measures analyzed passed the TRC test, and most of the residential measures passed the TRC test.

[6] Florida and Georgia, for example, require DSM programs to pass the RIM test.

DSM Potential Results

The total estimated residential energy conservation potential over the 20 year forecast period is about 1,186 GWh, approximately 17% of Nebraska Public Power District's forecast 2028 residential energy consumption of about 6,947 GWh. This is equal to annual average energy savings rate of about 0.8%, about 60 GWh. The calibration target for residential energy conservation potential from the benchmarking analysis that Summit Blue used to estimate NPPD's DSM potential is set towards the top of the residential DSM portfolios reviewed at 0.8% of residential sales. Approximately 79% of the energy and demand savings impacts are expected to be realized from existing homes, as compared to new construction.

Residential demand response measures have a demand reduction potential of about 131 MW over the forecast period. Cycling existing customers' central air conditioners during peak demand periods is estimated to have the largest achievable potential during this period, about 83 MW. Top-performing residential direct load control programs typically achieve impacts that amount to 10% or more of the utilities' residential peak demands, principally through direct load control of air conditioners during summer peak demand periods.

Table E-3. Summary and Five Year DSM Potential Results for Residential

Total Residential	20 Year Total	2008	2009	2010	2011	2012
Lighting						
Achievable Potential Demand Savings (kW)	23,263	233	465	931	1,163	1,279
Achievable Potential Energy Savings (kWh)	445,543,843	4,455,438	8,910,877	17,821,754	22,277,192	24,504,911
Measure Costs	$42,589,303	$425,893	$851,786	$1,703,572	$2,129,465	$2,342,412
Program Costs	$15,065,639	$150,656	$301,313	$602,626	$753,282	$828,610
HVAC						
Achievable Potential Demand Savings (kW)	59,620	596	1,192	2,385	2,981	3,279
Achievable Potential Energy Savings (kWh)	132,856,469	1,328,565	2,657,129	5,314,259	6,642,823	7,307,106
Measure Costs	$96,774,491	$967,745	$1,935,490	$3,870,980	$4,838,725	$5,322,597
Program Costs	$32,606,768	$326,068	$652,135	$1,304,271	$1,630,338	$1,793,372
Building Envelope						
Achievable Potential Demand Savings (kW)	110,325	1,103	2,207	4,413	5,516	6,068
Achievable Potential Energy Savings (kWh)	449,776,940	4,497,769	8,995,539	17,991,078	22,488,847	24,737,732
Measure Costs	$195,981,495	$1,959,815	$3,919,630	$7,839,260	$9,799,075	$10,778,982
Program Costs	$69,812,477	$698,125	$1,396,250	$2,792,499	$3,490,624	$3,839,686
Appliances						
Achievable Potential Demand Savings (kW)	1,867	19	37	75	93	103
Achievable Potential Energy Savings (kWh)	16,359,166	163,592	327,183	654,367	817,958	899,754
Measure Costs	$2,760,609	$27,606	$55,212	$110,424	$138,030	$151,834
Program Costs	$1,120,491	$11,205	$22,410	$44,820	$56,025	$61,627
Water Heating						
Achievable Potential Demand Savings (kW)	24,611	246	492	984	1,231	1,354
Achievable Potential Energy Savings (kWh)	141,170,068	1,411,701	2,823,401	5,646,803	7,058,503	7,764,354
Measure Costs	$27,788,846	$277,888	$555,777	$1,111,554	$1,389,442	$1,528,387
Program Costs	$13,762,217	$137,622	$275,244	$550,489	$688,111	$756,922
Demand Response						
Achievable Potential Demand Savings (kW)	130,884	1,309	2,618	5,235	6,544	7,199
Achievable Potential Energy Savings (kWh)	0	0	0	0	0	0
Measure Costs	0	0	0	0	0	0
Program Costs	$98,162,643	$981,626	$1,963,253	$3,926,506	$4,908,132	$5,398,945
Total Residential						
Achievable Potential Demand Savings (kW)	350,570	3,506	7,011	14,023	17,529	19,281
Achievable Potential Energy Savings (kWh)	1,185,706,486	11,857,065	23,714,130	47,428,259	59,285,324	65,213,857
Measure Costs	$365,894,745	$3,658,947	$7,317,895	$14,635,790	$18,294,737	$20,124,211
Program Costs	$230,530,235	$2,305,302	$4,610,605	$9,221,209	$11,526,512	$12,679,163

The total estimated commercial and industrial energy efficiency potential over the 20 year forecast period is about 2,343 GWh and 890 peak MW. 40% of this energy efficiency potential is projected to come from energy efficient lighting products, about 20% is projected to come from energy efficient HVAC equipment and controls, and about 38% of the total potential is expected to come from custom and motors measures. The total commercial energy efficiency potential amounts to approximately 19% of NPPD's forecast 2028 commercial energy consumption of about 12,451 GWh. This is equal to annual average energy savings of about 1.0% of annual commercial sales, about 117 GWh.

The commercial peak demand reduction potential is about 31% of NPPD's forecast 2028 commercial peak demand of 2,863 MW. The total commercial DSM program costs over the 20 year forecast period are estimated at about $365 million, or about $18 million per year on average. Commercial program costs ramp up over the period from about $4 million per year initially to about $20 million per year at full scale.

Table E-4. Summary and Five Year DSM Potential Results for C&I

Comm, Industrial, Gov't, & Irrig'n	20 Year Total	2008	2009	2010	2011	2012
Lighting						
Achievable Potential Demand Savings (kW)	306,614	3,066	6,132	12,265	15,331	16,864
Achievable Potential Energy Savings (kWh)	961,777,389	9,617,774	19,235,548	38,471,096	48,088,869	52,897,756
Measure Costs	$235,034,389	$2,350,344	$4,700,688	$9,401,376	$11,751,719	$12,926,891
Program Costs	$91,984,226	$919,842	$1,839,685	$3,679,369	$4,599,211	$5,059,132
HVAC & Controls						
Achievable Potential Demand Savings (kW)	103,197	1,032	2,064	4,128	5,160	5,676
Achievable Potential Energy Savings (kWh)	469,889,574	4,698,896	9,397,791	18,795,583	23,494,479	25,843,927
Measure Costs	$60,312,881	$603,129	$1,206,258	$2,412,515	$3,015,644	$3,317,208
Program Costs	$84,565,108	$845,651	$1,691,302	$3,382,604	$4,228,255	$4,651,081
Custom & Motors						
Achievable Potential Demand Savings (kW)	177,857	1,779	3,557	7,114	8,893	9,782
Achievable Potential Energy Savings (kWh)	887,601,689	8,876,017	17,752,034	35,504,068	44,380,084	48,818,093
Measure Costs	$248,228,665	$2,482,287	$4,964,573	$9,929,147	$12,411,433	$13,652,577
Program Costs	$160,071,310	$1,600,713	$3,201,426	$6,402,852	$8,003,566	$8,803,922
Demand Response						
Achievable Potential Demand Savings (kW)	302,064	30,206	27,186	27,186	24,165	24,165
Achievable Potential Energy Savings (kWh)	23,646,513	2,364,651	2,128,186	2,128,186	1,891,721	1,891,721
Measure Costs	0	0	0	0	0	0
Program Costs	$28,019,523	$2,801,952	$2,521,757	$2,521,757	$2,241,562	$2,241,562
Hot Water Heating						
Achievable Potential Demand Savings (kW)	3	0	0	0	0	0
Achievable Potential Energy Savings (kWh)	41,016	410	820	1,641	2,051	2,256
Measure Costs	5,316	53	106	213	266	292
Program Costs	$ 1,905	$ 19	$ 38	$ 76	$ 95	$ 105
Total CI						
Achievable Potential Demand Savings (kW)	889,735	8,897	17,795	35,589	44,487	48,935
Achievable Potential Energy Savings (kWh)	2,342,956,182 0.410	23,429,562	46,859,124	93,718,247	117,147,809	128,862,590
Measure Costs	$543,581,250	$5,435,812	$10,871,625	$21,743,250	$27,179,062	$29,896,969
Program Costs	$364,642,072	$3,646,421	$7,292,841	$14,585,683	$18,232,104	$20,055,314

The total estimated overall energy efficiency potential over the 20 year forecast period is about 3,529 GWh and 1,240 peak MW. Over 40% of this energy efficiency potential is projected to come from energy efficient lighting products, about 21% is projected to come from energy efficient HVAC equipment and controls, and about 25% of the total potential is expected to come from custom and motors measures. The total overall energy efficiency potential amounts to approximately 18% of NPPD's forecast 2028 overall energy consumption of about 19,400 GWh. This is equal to annual average energy savings of about 1.0% of annual overall sales, about 176 GWh.

The overall peak demand reduction potential is about 31% of NPPD's forecast 2028 overall peak demand of 4,000 MW. The total overall DSM program costs over the 20 year forecast period are estimated at about $595 million, or about $30 million per year on average. Overall program costs ramp up over the period from about $6 million per year initially to about $33 million per year at full scale.

Table E-5. Overall Summary and Five Year DSM Potential Results (for Res & C&I)

Total Potential (Res & Comm)	20 Year Total	2008	2009	2010	2011	2012
Lighting						
Achievable Potential Demand Savings (kW)	329,877	3,299	6,598	13,195	16,494	18,143
Achievable Potential Energy Savings (kWh)	1,407,321,232	14,073,212	28,146,425	56,292,849	70,366,062	77,402,668
Measure Costs	277,623,692	2,776,237	5,552,474	11,104,948	13,881,185	15,269,303
Program Costs	$ 107,049,865	$ 1,070,499	$ 2,140,997	$ 4,281,995	$ 5,352,493	$ 5,887,743
HVAC & Domestic Hot Water						
Achievable Potential Demand Savings (kW)	187,431	1,874	3,749	7,497	9,372	10,309
Achievable Potential Energy Savings (kWh)	743,957,127	7,439,571	14,879,143	29,758,285	37,197,856	40,917,642
Measure Costs	184,881,533	1,848,815	3,697,631	7,395,261	9,244,077	10,168,484
Program Costs	130,935,997	1,309,360	2,618,720	5,237,440	6,546,800	7,201,480
Building Envelope						
Achievable Potential Demand Savings (kW)	110,325	1,103	2,207	4,413	5,516	6,068
Achievable Potential Energy Savings (kWh)	449,776,940	4,497,769	8,995,539	17,991,078	22,488,847	24,737,732
Measure Costs	195,981,495	1,959,815	3,919,630	7,839,260	9,799,075	10,778,982
Program Costs	$ 69,812,477	$ 698,125	$ 1,396,250	$ 2,792,499	$ 3,490,624	$ 3,839,686
Appliances and Office Equipment						
Achievable Potential Demand Savings (kW)	1,867	19	37	75	93	103
Achievable Potential Energy Savings (kWh)	16,359,166	163,592	327,183	654,367	817,958	899,754
Measure Costs	2,760,609	27,606	55,212	110,424	138,030	151,834
Program Costs	$ 1,120,491	$ 11,205	$ 22,410	$ 44,820	$ 56,025	$ 61,627
Custom & Motors						
Achievable Potential Demand Savings (kW)	177,857	1,779	3,557	7,114	8,893	9,782
Achievable Potential Energy Savings (kWh)	887,601,689	8,876,017	17,752,034	35,504,068	44,380,084	48,818,093
Measure Costs	248,228,665	2,482,287	4,964,573	9,929,147	12,411,433	13,652,577
Program Costs	$ 160,071,310	$ 1,600,713	$ 3,201,426	$ 6,402,852	$ 8,003,566	$ 8,803,922
Demand Response						
Achievable Potential Demand Savings (kW)	432,947	31,515	29,803	32,421	30,709	31,364
Achievable Potential Energy Savings (kWh)	23,646,513	2,364,651	2,128,186	2,128,186	1,891,721	1,891,721
Measure Costs	0	0	0	0	0	0
Program Costs	$ 126,182,166	$ 3,783,579	$ 4,485,010	$ 6,448,263	$ 7,149,694	$ 7,640,507
Total						
Achievable Potential Demand Savings (kW)	1,240,305	12,403	24,806	49,612	62,015	68,217
Achievable Potential Energy Savings (kWh)	3,528,662,668	35,286,627	70,573,253	141,146,507	176,433,133	194,076,447
Measure Costs	909,475,995	9,094,760	18,189,520	36,379,040	45,473,800	50,021,180
Program Costs	$ 595,172,306	$ 5,951,723	$ 11,903,446	$ 23,806,892	$ 29,758,615	$ 32,734,477

Conclusions and Recommendations

The DSM benchmarking analysis results presented in this report should give NPPD management confidence that a variety of utilities in the Midwest are achieving large- scale results from their DSM programs. Peak demand and energy reductions of 1.0% of utilities' baseline commercial peak demands and energy sales and 0.8% of residential peak demand and energy sales are being achieved by a variety of Midwestern utilities. While the details of large impact DSM program portfolios often differ significantly between utilities, several common elements have been identified by the analysis conducted:

Large impacts are being realized from both lighting and multi-product energy efficiency programs for both residential and commercial sectors.

Significant impacts are being achieved from residential and commercial new construction energy efficiency programs.

C&I custom rebate energy efficiency programs have produced significant impacts for some utilities.

The largest sources of uncertainty regarding the estimates that Summit Blue has developed to date for NPPD stems from using secondary information to profile NPPD's commercial customers. The secondary end use estimates for electric use have higher than actual estimates for the amount of electricity that is used for "miscellaneous" purposes. This is due to the lack of precision in the end use estimates developed by the original sources of the data, such the Department of Energy's Commercial Building Energy Consumption Survey.

Utilities that choose to significantly invest in DSM programs often make significant periodic investments to develop and update such data to aid their DSM program planning. For example, Xcel Energy in Minnesota conducts large-scale market assessments and DSM potential studies that include significant on-site customer data collection every five to ten years. The Iowa utilities conduct DSM potential studies about every five years to support their periodic DSM program filings with their regulators. These utilities collected significant customer data as part of their current DSM potential study.

If NPPD wishes to improve its current customer and load data for DSM planning purposes, Summit Blue suggests that the Company conduct market assessment projects for its customers in a multi-phased approach:

1. Start with telephone surveys of representative samples of several hundred customers in each customer sector (residential, commercial, industrial). These surveys should collect both customer awareness and attitude information, as well as appliance and equipment saturation information, as much as possible.

2. Conduct on-site validation surveys that are done in more depth for representative sub-samples of 30-100 telephone survey respondents per sector. The focus of the on-site surveys is on collecting detailed customer facility information and energy equipment inventories.

3. Develop building simulation models for representative customers in each building segment of interest, such as office buildings or single-family homes. Calibrate the simulation models to the customers' actual electric and fossil fuel consumption.

4. Conduct end-use metering for very small sub-samples of the on-site survey customers, and use the results to further calibrate the building simulation models.

5. Document the results of the study, including:

    a. Billing statistics and customer counts by customer type for each customer sector and key market segment, such as office buildings.

    b. Develop end use peak demand and energy consumption profiles for each customer sector and key market segment.

    c. Develop DSM measure saturation estimates for each customer sector and key market segment.

    d. Develop detailed DSM potential estimates for each customer sector and key market segment.

This information would be very useful for long-term DSM program planning, and also to help focus program resources on the key market segments in the near term. This type of market intelligence can also have applications far beyond DSM program planning if broader planning considerations are incorporated into the project designs.

If you would like the entire Summit Blue "NPPD DSM Potential Study and Plan", please contact Teresa Pasonault at tkpason@nppd.com.

Appendix F - IRP Model Verification - Detailed Description

One of the fundamental requirements for the IRP model is the ability to provide a reasonable estimate of annual generation from existing and new resources over the study period. In past studies NPPD used commercially available software, PROMOD, to develop the annual generation projections, which were then transferred to a spreadsheet model for additional analysis. For purposes of the IRP analysis, a high level method for projecting unit generation was developed that could be implemented directly in the IRP spreadsheet model.

The model starts with annual generation estimates for existing and committed resources, which are based on PROMOD results. The first six years (2008 – 2013) use results from the 2007 Rate Outlook analysis. These estimates were later expanded through the full model study period (2008 – 2027) using the results from extended PROMOD simulations. Initial generation estimates for future resource alternatives utilized capacity factor assumptions developed by NPPD Corporate Planning & Risk personnel using a combination of resources (EPRI, etc) and engineering judgment. These basic generation assumptions are stored in the "Input" worksheet of the model and then transferred to the "Calculations" worksheet, as required.

The model needs to have a method to adjust these initial generation estimates in order to respond to changes in other key model assumptions, such as different energy forecasts, as well as to allow different resource plans to be simulated. In the IRP model, this function is achieved via annual energy scale factors, which are multiplied by the initial generation estimates to bring overall generation into balance with native load energy requirements[16]. Currently eight separate scale factors are used to adjust existing/committed resource generation and purchases[17], while another four scale factors are used to adjust the generation of future resource alternatives[18].

Some resources (e.g., nuclear, hydro, wind, etc.) are treated as non-dispatchable units. The initial generation estimates for these resources are not adjusted by the model, rather the generation from other dispatchable resources is adjusted to bring generation and load into balance.

It is necessary for this balancing of generation and load to be performed dynamically within the IRP model. Therefore a Microsoft® Visual Basic program, EBal[19], was developed to automate the process[20].

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[16] More specifically, net NPPD generation (total generation, less long-term sales to other utilities), plus non-firm energy purchases, less non-firm energy sales, should balance native load energy on an annual basis.

[17] Separate scale factors are provided for GGS1, GGS2, Sheldon 1, Sheldon 2, Nebraska City Unit 2 purchase, BPS, existing peaking units (Canaday, gas turbine peaking units, municipal internal combustion units), and non-firm energy sales.

[18] Scale factors are provided for future baseload (coal), intermediate (combined cycle & gas-fired cogeneration), storage (pumped storage hydro), and peaking (gas turbine) resource alternatives.

[19] The EBal program incorporates the Microsoft® Excel Solver tool to iteratively determine the combination of scale factors that will bring generation into balance with load.

Because of the importance of having reasonably accurate generation projections[21], a number of multi-year comparative PROMOD simulations[22] were conducted in order to benchmark the IRP model to the PROMOD dispatch results. Of particular interest was the impact on the level of non-firm sales with significant additions of non-dispatchable generation (such as wind) and how those impacts would change with the addition of energy storage units. Initial comparisons indicated that the IRP Model tended to underestimate non-firm sales energy[23], relative to PROMOD results, for these cases. Using the results from the PROMOD simulations, regression analyses were performed to develop polynomial equations[24] relating non-firm sales amounts to native load (NL)[25], non-dispatchable generation (ND)[26], dispatchable baseload generation (BL)[27], and storage unit energy (both pumping and generation).

For the "general" non-firm sales category, regression analysis suggested that an equation of the form $\boldsymbol{y} = a + b*LN(\boldsymbol{x})$ would provide the best fit. In this equation, $\boldsymbol{y}$ is equal to the annual non-firm sales amount (in MWh), $\boldsymbol{x}$ is equal to $c*ND + BL - NL$[28] (all in MWh), a = -25,589,566, b = 1,812,444, and c = 1.225. The goodness of fit, or R^2 statistic, for the regression was approximately 0.95. Exhibit F-1 shows the data points[29] used in the regression, along with the resulting curve.

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[20] Several additional Visual Basic programs were developed to save the scale factors resulting from running the EBal program for later recall, resulting in faster recalculation of the model during full Monte-Carlo simulations.

[21] Projected unit generation is used in the IRP model to compute variable production costs (e.g., fuel, VOM), as well as to estimate annual air emissions, and associated costs.

[22] Four basic PROMOD cases were developed, generally corresponding with the Min1, Mod1, Ext1, & Ext2 resource plans.

[23] Two main categories of non-firm energy sales are estimated in the IRP model, in order to more closely track the PROMOD simulation results: 1) General non-firm sales, which are priced based on the assumptions discussed in Section 8.3.6; and 2) Dump energy sales, which represent unavoidable surplus must-run minimum segment generation that cannot be used by NPPD for its own requirements. As is the case in PROMOD, this dump energy is priced at a nominal rate of $5.00/MWh, which is significantly below the normal 7x24 market price assumptions.

[24] Separate equations were developed for projecting general non-firm sales and dump energy sales.

[25] Native Load is NPPD's projected annual native load energy requirements, less any projected energy efficiency impacts.

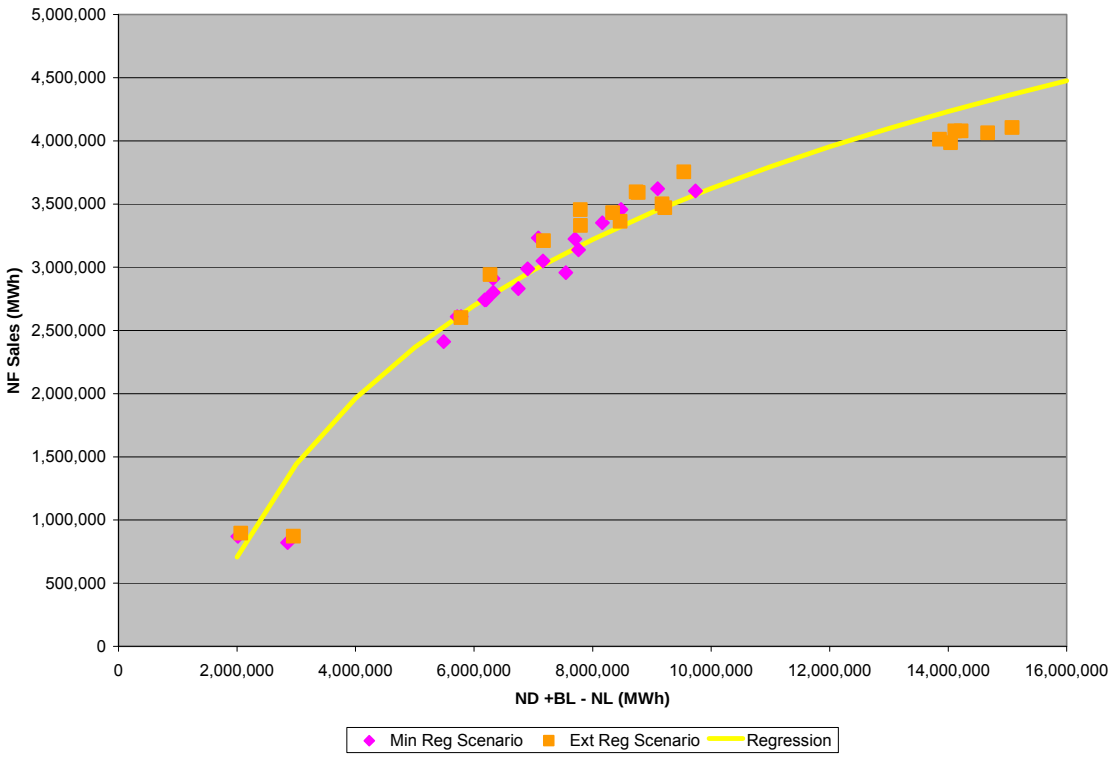
[26] Non-dispatchable generation includes Nuclear (CNS and future), Hydro (NPPD, Loup, Central), WAPA energy purchases, Wind (existing and future), Baseload Cogeneration (committed and future coal/biomass), and Solar.

[27] For purposes of the regression analysis, dispatchable generation is an estimate of the maximum annual (100% CF) energy from GGS1, GGS2, Sheldon1, Sheldon2, Nebraska City Unit 2 purchase, and future coal.

[28] This term was later modified to $\boldsymbol{x} = c*ND + BL - NL + d*PSGen$, where PSGen is the annual storage unit generation (in MWh) and d is a constant (0.550). The general interpretation is that as non-dispatchable generation, dispatchable baseload generation, and storage unit generation increases, non-firm energy sales will also increase. Conversely, as native load energy requirements increase, non-firm energy sales will decrease.

[29] PROMOD results from two simulations were used in the regression analysis to ensure that the resulting equation would generally be applicable over a wide range of non-dispatchable generation amounts.

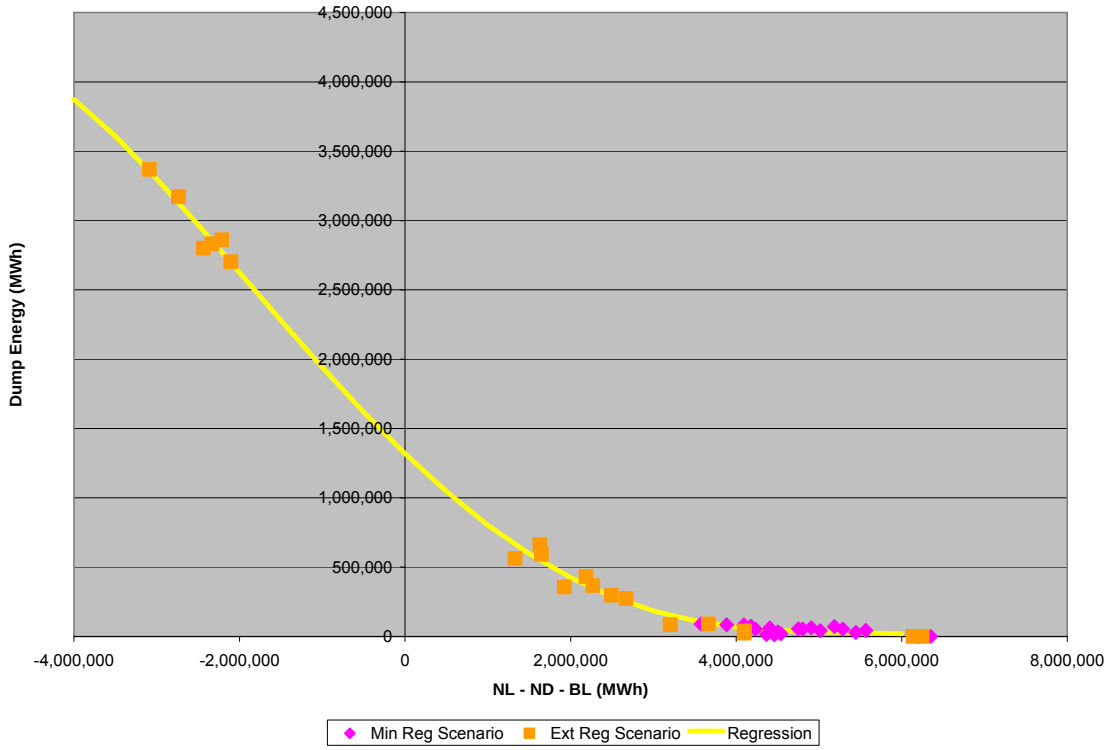
Exhibit F-1 Non-firm Sales Regression Calculations



In the case of "dump energy" sales, regression analysis indicated that an equation of the form $\boldsymbol{y} = a + b_{*}\boldsymbol{x} + c_{*}\boldsymbol{x}^2 + d_{*}\boldsymbol{x}^3 + e_{*}\boldsymbol{x}^4$, would provide a reasonable fit for the PROMOD results. In this equation, $\boldsymbol{y}$ is equal to the annual dump energy sales amount (in MWh), $\boldsymbol{x}$ is equal to NL -ND - $f_{*}BL$[30] (all in MWh), a = 1,317,900, b= -0.57526, c = 5.5548E-08, d = 6.2168E-15, e = -9.1829E-22, and f = 0.3. The goodness of fit, or R^2 statistic, for the regression was approximately 0.99. Exhibit F-2 shows the data points used in the regression, along with the resulting curve.

[30] This term was later modified to $\boldsymbol{x}$ = NL -ND - $f_{*}BL + g_{*}PSPump$, where PSPump is the annual storage unit pumping energy (in MWh) and g is a constant (0.950). The general interpretation is that as non-dispatchable generation and dispatchable baseload generation increases, dump energy sales will also increase. Conversely, as native load energy requirements and storage energy increase, dump energy sales will decrease.

Exhibit F-2 Dump Energy Sales Regression Calculations



In the IRP model, these equations were used to estimate the non-firm and dump energy sales amounts for each year of the study period and unit generation was then adjusted to bring it into balance with the forecasted load. Using this modified approach, energy sales and unit generation projections in the IRP model were brought into reasonable alignment with the PROMOD simulation results.

NF Transaction Pricing Calibration

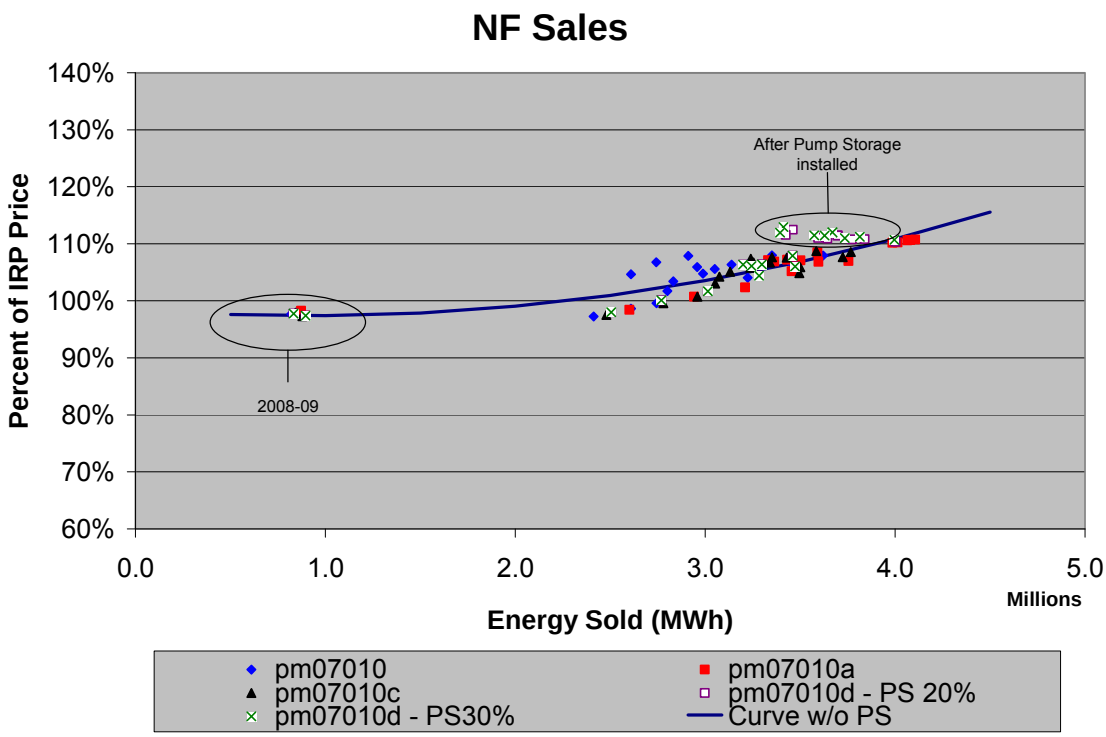
PROMOD simulation results were also used to adjust the assumptions used by the IRP model to price non-firm energy sales and purchases. PROMOD uses hourly profiles to price non-firm transactions. Thus the resultant average price can vary depending on when non-firm energy is purchased or sold. In the IRP model a pre-determined average annual value is used to price non-firm transactions, regardless of the amount of energy purchased or sold.

Once again, regression analyses were performed in order to develop suitable adjustments to the IRP model assumptions. For each year of the study, the average annual price for purchases and sales was computed based on the PROMOD simulations and compared to the IRP model assumptions. Using this information the ratio between PROMOD and the IRP model prices could be calculated and a suitable adjustment factor estimated. These

comparisons were completed for resource plans with and without the addition of energy storage units.

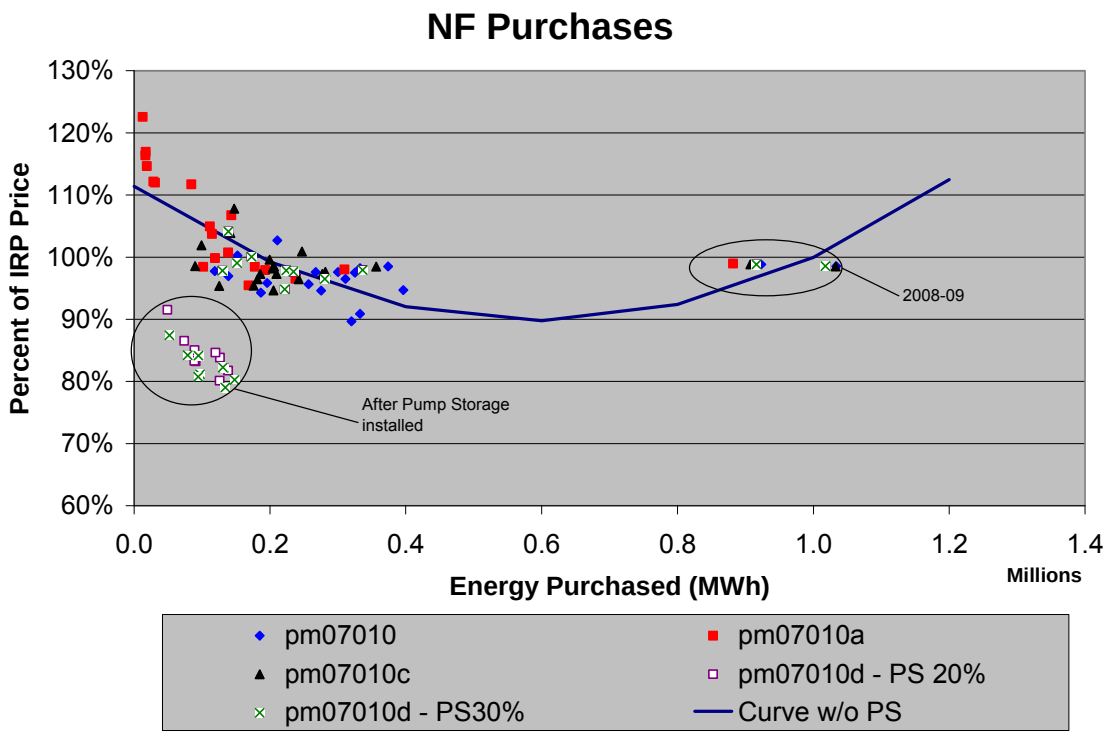
For non-firm sales, the analysis suggested that an equation of the form $\boldsymbol{y} = a + b_{*}\boldsymbol{x} + \boldsymbol{c}_{*}\boldsymbol{x}^2$ would provide the best fit, where $\boldsymbol{y}$ is the adjustment factor, $\boldsymbol{x}$ is the annual non-firm sales level (in MWh), a = 0.9855, b = -2.5717E-08, and c = 1.4118E-14. Exhibit F-3 shows the data points used in the regression, along with the resulting adjustment curve.

Exhibit F-3 Non-firm Energy Sales Price Regression Calculations



In the case of non-firm purchases, the analysis suggested that an equation of the form $\boldsymbol{y} = a + b_{*}\boldsymbol{x} + \boldsymbol{c}_{*}\boldsymbol{x}^2$ would provide the best fit, where $\boldsymbol{y}$ is the adjustment factor, $\boldsymbol{x}$ is the annual non-firm purchase level (in MWh), a = 1.1140, b = -7.3015E-07, and c = 6.1582E-13. Exhibit F-4 shows the data points used in the regression, along with the resulting adjustment curve.

Exhibit F-4 Non-firm Energy Purchase Price Regression Calculations



Looking at Exhibits F-3 & F-4, it is apparent that an additional adjustment for pricing is appropriate when energy storage units are in operation. Further analysis suggested that an additional multiplication factor of 1.03 was a reasonable adjustment for non-firm sales[31], while a multiplication factor of 0.8 was determined to be appropriate for non-firm purchases[32].

These adjustment factors are applied to the basic price assumptions in the IRP model in order to determine the final price to be used in the cost calculations.

[31] The resulting adjustment factor equation for the non-firm sales price, with energy storage units operating, would be $\boldsymbol{y} = 1.03*(a + b*\boldsymbol{x} + \boldsymbol{c}*\boldsymbol{x}^2)$, where a, b, c, x, and y have the same meanings and values as previously stated.

[32] The resulting adjustment factor equation for the non-firm purchase price, with energy storage units operating, would be $\boldsymbol{y} = 0.8*(a + b*\boldsymbol{x} + \boldsymbol{c}*\boldsymbol{x}^2)$, where a, b, c, x, and y have the same meanings and values as previously stated.

Appendix G – Summary of IRP Public Comments

Summary of questions/answers from the IRP Public Meetings

Kearney - February 18, 2008
Lincoln – February 19, 2008
Norfolk – February 20, 2008
Scottsbluff- February 28, 2008
North Platte – March 4, 2008

GENERAL

What is the estimated life of existing NPPD generating resources? Do you consider the age of existing units in the IRP?
Yes, in some of the resource plans we have older units being replaced or repowered.

I understand that Tire Derived Fuel (TDF) and some hazardous waste is being incinerated at the Ash Grove Cement plant in Louisville. Is TDF a potential fuel option for NPPD?
TDF has been test burned in the past at Sheldon Station but at that time there were issues related to the supply and its quality. TDF is still a potential fuel option at this time for Sheldon Station.

Presentation graph indicated that ~10% of NPPD's energy requirements were met with purchases. Does NPPD expect these purchases to continue in the future?
Yes, it's what we purchase on a yearly basis. The largest portion is hydroelectric capacity and energy purchased from the Western Area Power Administration (WAPA).

Will NPPD have excess capacity to sell in a few years? How much power do we buy and sell? Is NPPD a seller in the market and are they making money?
Yes, NPPD will have excess capacity to sell and is considered to be a net seller in general. NPPD makes money selling to the market, helping to offset costs and keeping Nebraska rates as low as possible.

Does NPPD expect non-firm energy sales to continue at their current level in the future (next 3-4 years)? To whom is this non-firm energy sold?
Yes, NPPD expects to continue to be net seller for non-firm energy. Currently the majority of these sales are to the Mid-Continent Area Power Pool.

I recall that at one time NPPD was considering building a transmission line to Canada (MANDAN) in order to exchange power. Would such a project be considered again in the future?
There are no plans at this time to consider a MANDAN type project.

How does NPPD factor in the public's attitude with respect to resources, e.g., wind and nuclear? And does NPPD implicitly assume these options can be sited and built?
These meetings are a primary way to obtain and incorporate public views on our future resource mix. We also hold meetings with our wholesale customers and board to examine these resources. We also will accept written or electronic comments. Yes, we assume the options we have included can be implemented.

Is the IRP a one-time or continuous process?
No, it is an ongoing process.

Load growth is mostly along the 1-80 corridor, what about smaller communities?
Industrial and irrigation are major drivers of NPPD's load growth. Ethanol in particular is a strong presence in smaller communities.

Have you considered load growth due to electric vehicle plug-ins in the future?
Not directly in the models. NPPD is working with the Electric Power Research Institute and the University of Nebraska-Lincoln on these electric vehicle plug-ins and future technologies.

What is NPPD doing to bury lines underground? As with the ice storm, there is a cost factor to the customer. Wouldn't it be best to bury these lines underground to avoid damage from these storms?
This works well for distribution lines. It is technically possible, but extremely expensive to bury high voltage transmission lines. There is technology today to help reinforce our transmission structures and we are using some of that technology as we make improvements to our system.

Is NPPD participating in some of the large regional transmission studies that have been in the news?
We are monitoring progress and providing input.

Who will be in control of the transmission balancing area?
NPPD would still be in control, but we could share that responsibility with others to balance overall load and generation.

Will gas be the fuel of choice? Can we convince people that nuclear is safe?
There is a lot of resurgence in nuclear interest, but a lot of cost uncertainty. There appears to be additional support from Congress to increase nuclear power, plus it is not a contributor to greenhouse gas.

RATES

What does NPPD expect for Rate Increases over the next couple of years?
Retail Area - 3-4% for Residential; 5% for Industrial.

Didn't last year's ice storm related expenses increase retail rates more than 5%?

Replacement power and natural gas expenses were the largest impacts for NPPD. To help offset those costs not reimbursed by the Federal Emergency Management Agency, NPPD utilized funds from its Rate Stabilization Account and implemented a Production Cost Adjustment(PCA) for one year to help defray those expenses. The PCA will end in May 2008.

Will recovery of generation capacity (participation purchases) cause rates to increase?
No. This is not a concern.

WIND POWER

Is the intermittent nature of wind a detriment or benefit to selling wind energy outside the state? *Wind cannot be dispatched; therefore it is more difficult to sell a variable resource. Although forecasting wind helps, day ahead energy sales are more difficult for wind powered generation*

If private companies build new wind facilities, who is responsible for building the transmission to interconnect with those facilities? *Typically the owner of the generation will be responsible for the cost.*

How are other States dealing with the integration of large amounts of wind generation into their electrical system? *Good forecasting of wind, physically dispersed wind generation, utilization of hydro generation and natural gas powered generation, and sharing the variability over a large control area.*

How many wind towers/turbines would be required to replace one of NPPD's current power plants?
This would depend on the size of the turbines involved. Replacing 600 megawatts of electricity (approximately one unit at NPPD's Gerald Gentleman Station) with 2 megawatt wind turbines, approximately 1,765 wind turbines would be needed, assuming that only about 17% of each turbine's maximum capacity would be available at the time of NPPD's summer peak demand.

What is the expected lifetime of a wind turbine?
Experience today suggests that most turbines are designed to last 20 years. The wind industry is still in its early stages utilizing multi-MW sized equipment, so we are still learning more concerning maintenance issues related to the generators and turbines themselves.

What is NPPD doing to provide information about the issues associated with wind generation in simple terms that can be easily understood by a layperson? Education is important. We could do more to get the factual information to the public.
NPPD is working with the Nebraska Power Association (NPA) to get more information out on wind-generated power for use by the general public. Our Renewable Energy Development Staff also meets with the public and provides basic information about large-

scale wind development on a regular basis. NPPD also had a representative participating with the Nebraska Wind Working Group on its five-day state tour in February.

Why is NPPD outsourcing its wind facility ownership and construction?
The last project, Ainsworth, NPPD did own and construct. However, private developers can get a significant production tax credit that NPPD, being a public power entity, cannot obtain. So we are partnering with private developers hoping to obtain the wind energy at a lower cost for the benefit of our customers. This also reduces NPPD's risk on construction, maintenance, and operation of a wind farm, putting those costs on a developer. NPPD's rate for purchasing power from these facilities is comparable to other generation costs.

We read continuously that we are the 6th windiest state but we are only 19th in wind production. What is holding up Nebraska investment in wind?
A combination of things: Nebraska is an entirely public power state, so public utilities are not eligible for Production Tax Credits (approximately two cents per kilowatt hour) that are available to private developers and Community-Based Energy Development groups. Nebraska statutes require low cost and need for construction of facilities. LB 629 passed in 2007 also encourages the development of renewable energy projects through C-BED groups.

I'm tired of hearing that NPPD is learning about wind. Wouldn't it be better to steal what states like Minnesota have learned about wind?
NPPD has looked at what other states are doing, for example we have researched Minnesota's wind integration studies. Load profiles and generation is different in each state. Wind energy is important to the area. We collected data from eight different locations around the state before we chose Ainsworth. We are moving thoughtfully in the development of more wind power by planning for more wind studies throughout the state. Doing a complete study involves pulling data from all four seasons, thus a study will take approximately a year to do. This does not include the time that it takes to secure a potential wind farm footprint in case an area selected for a study turns out to be a promising location. NPPD is moving in a thoughtful and practical way to make sure we are making good investments.

What was the capacity factor percentage of Ainsworth?
Capacity factor was 42%; accredited capacity value is 17%.

What does ice do to wind turbines?
There is a computer that keeps track of the balance on turbines and it will shut the generator down if too much ice forms and offsets the balance.

Are wind turbines high maintenance generation?
Wind turbines require maintenance, just like any mechanical equipment that has moving parts. Ainsworth had a 42% capacity factor last year, but we've encountered problems with blade and gear boxes this year. We've had around the 35% capacity factor in 2007.

Are more private entities interested in developing wind generation?
Yes. We had seven companies or C-BED groups submit proposals during a Request for Proposal period last summer. NPPD is also aware of several other private developers who are looking at developing wind farms in the state.

Is the Nebraska sales tax incentive for equipment only?
Yes. Private owners can take advantage of the tax credit and we get lower cost electricity.

What is the typical pay back period for investment?
10 years or less. The Production Tax Credit (PTC) expires after 10 years for private investors.

I've seen information on vertical turbines. Have you looked at these?
Yes, we have looked at these types of turbines but have made no decisions on them since NPPD does not have plans to build another wind farm in the near-term. It is possible that they could be used when new turbines are installed at Springview as part of a technology demonstration project.

What percentage of wind can be put in the next 20 years and utilize GGS to assure that the lights will come on when we flip the switch.
We are studying how much wind should be integrated into our overall load.

If investors build wind, how much does NPPD have to guarantee they'll take?
We take it and pay for it as it gets generated.

How do we keep GGS going if the wind stops?
The levels we are looking at now should not adversely affect our system.

Florida (Jacksonville Energy Authority) bought (10) megawatts of wind in Ainsworth. How do you get that to them?
We keep the electricity and they get the renewable tax credits. Omaha Public Power District, the City of Grand Island, Lincoln Electric System, and the Municipal Energy Authority of Nebraska, also bought part of the Ainsworth Wind Energy Facility output.

In your studies, do you look at regional areas to balance how much wind you can handle? Are you looking at wind generation in an eight-state area?
It's best to look at large regions. The Department of Energy is working to help fund states or regions doing these studies.

What does nameplate mean and is future wind nameplate or accredited?
Nameplate is the size of generator on the tower and future wind is referenced in Nameplate values.

What does accredited mean?
What we would expect the unit to generate at the time of our system peak

Where did the 17% accreditation value come from?
17% accreditation comes through information from the Mid-Continent Area Power Pool (MAPP) accreditation process for the Ainsworth Wind Energy Facility.

NET METERING

Will NPPD pursue net metering? Would NPPD consider offering incentives to encourage their customers to install their own distributed generation (e.g. wind, solar, etc.)? What is NPPD's position on net metering, and how does the pricing work – at retail price?

There is not a net metering law currently in Nebraska. NPPD's Board is reviewing the issue of net metering and expects to consider a policy in the spring for the customers served at retail. NPPD is supporting the bill in the Natural Resources Subcommittee relating to net metering.

Where does NPPD stand on Time of Day rates?
NPPD is examining Time of Day rates as part of the Public Utility Regulatory Policy Act (PURPA) standards review as required by Federal Energy regulatory Commission (FERC) We are also pursuing a pilot project for our retail residential customers.

RENEWABLES (other than wind)

I understand that John Deere has been involved in promoting the development of renewable generation. Are they involved in Nebraska?
John Deere Corporation is involved in working with Community-Based Energy Development, primarily in the farm community. We are not sure as to how active they are in Nebraska with C-BED projects.

Is NPPD looking into hydrogen production as a source of energy storage associated with wind generation? Is NPPD studying hydrogen?
Yes this would be a part of our research activities and association with the University of Nebraska-Lincoln.

Why is there not more solar power in Nebraska?
Today solar power is much more expensive than other renewable resources. For example, the Ainsworth Wind Energy Facility was built for $81 million and has the ability to generate 60 megawatts of power, with a capacity factor of 42%. A solar project was built at Nellis Air Force Base that cost $114 million and is 18 megawatts in size, with a capacity factor of about 25%. The Ainsworth wind farm uses about 50 acres of land; the solar farm covers 150 acres. Solar technology is improving so prices should go down in the future.

With the new water laws, is it practical to consider pumped storage?
It is worthy of more research. It seemed right to at least take a look at pumped storage technology for the future.

ENERGY EFFICIENCY

What kinds of (energy) conservation programs are being promoted in the IRP?
Energy efficiency programs; high efficiency lighting, air conditioning, agricultural irrigation pumps and motors.

I understand that tankless water heaters are not very efficient and not recommended. What is NPPD's opinion?
From a utility perspective – tankless water heaters result in high demand and do save energy. Due to the fact that the load profile is sporadic (peaks and then off), it would be difficult for a utility to advocate their use.

With existing 500+ MW demand reduction why only 161 MW energy efficiency in the plan?

1. *The 161 listed is only the new targeted megawatts for reduction.*
2. *They are two different categories – most of the new load control for irrigation, air conditioning, etc. is subtracted from the load forecast and does not show up as a resource in energy efficiency.*
3. *Energy efficiency is mostly an action where energy is actually saved while load control mostly shifts energy usage to a different time period.*

How much does the 161 MW of energy efficiency represent? It seems too modest an effort.
Approximately 5% reduction in summer peak demand (in 2027), including the associated 15% RCO requirement. We are trying to learn as we go—agreed it is fairly modest.

How will NPPD provide incentive to our wholesale customers to help them get on board with energy efficiency?
We have consulted with Bonneville Power who has similar structure (interfacing with wholesale customers) and we believe some of their approaches may be adaptable to our situation. Plus we will continue to get Wholesale customer involvement in developing the programs, work out any issues with our customers, and provide programs that our customers are interested in.

Is any or all energy efficiency at the customer end? What is used in the assumptions? Is it customer or NPPD?
Assumptions used are end-use customer view.

CLIMATE CHANGE

What is the cost effect of the CO2 regulations?
One comparison would be that the general study period cost increases from 12 billion to 14 billion. (If one looks at page 91 of the IRP report, the lowest cost for No CO2 cost is $11,831 million and the lowest cost for High CO2 cost is $14,277 million, which is a 21% increase in NPV production cost for 20 years. Assuming production is 2/3 of retail this

would amount to a minimum of a 14% increase in retail pricing. The price of CO2 could be roughly estimated to be zero to begin and 35% at the end of the study period. But it all depends on the actual regulation and the innovative solutions to deal with it.)

Why does it seem that NPPD's CO2 emissions are increasing significantly when it is not adding much new fossil generation?
Because through generation recapture (some being fossil) and use of that generation for our native load purpose, and selling less to the market, we have more fossil generation emissions that become the responsibility of NPPD into the future. Also we do have some new coal generation assumed in some of the expansion plans.

Did NPPD look at the worst case for CO2 cost impact?
It may not be the "worst case" possible, but in the extreme regulatory scenario we looked at cap and trade regulations beginning in the 2012-2014 timeframe, and starting in a price range of $6-30/metric ton. These prices increase to $19-92 in 2027. So the highest cost case we studied started at $30 in 2012 going to $92 in 2027.

Why are the carbon credits for no-till farming currently being purchased by Canada so low in the Midwest?
Most of the regulations being considered have limitations on the qualifications of such "offsets", in the number, quality, and locations that can be used. For a regulation to actually achieve emission reductions, these allowances and offset prices will have to be higher than those current values of $1-4 per ton.

Does Powder River Basin coal have more or less SO2 than average?
PRB coal is low sulfur, so less SO2.

Has the IRP considered more regulation on future coal fired facilities?
NPPD won't make a decision on a future coal plant until we know more about future environmental regulation. NPPD will add resources that make the most sense given the regulatory environment.

Does NPPD have a position on cap and trade?
NPPD's Board approved a Climate Change Policy Statement at its February Board meeting. Whether Congress decides to pursue a market-based cap-and-trade program or a greenhouse gas fee program, the program should be based on targets that recognize the limitations of currently available technology and provide reasonable transition periods to avoid undue cost impacts on consumers.

How big of an impact are we looking at with carbon legislation?
We are currently working with environmental experts. We are looking at $6-30/tons initially in the 2012-2014 timeframe, but 20 years from now it could be as high as $90/ton.

Does the emission tax apply to all emissions or just incremental?

Many proposed carbon regulation programs allocate a certain number of "free" emission allowances to each emitting entity. In this case, the entity would only pay for emissions that exceeded its available allowances.

CO GENERATION

What weight (consideration) does NPPD give to customer generation, or how much is counted in the plan?
NPPD mostly has incorporated industrial cogeneration into its IRP. But if the costs of smaller customer generation do come down we might expect there to be more installed.

NUCLEAR ENERGY

What about the concerns over nuclear fuel price escalation and is the U.S. going to recycle its spent fuel?
Recently a significant amount has come from re-processed nuclear weapons, which have kept prices down, but that source is winding down. So prices are escalating, but mines are expected to open up providing a stabilization of the pricing and supplies, as needed.

Rates are going up no matter what, why not nuclear since it's the cheapest resource?
Nuclear is very cheap fuel wise, but not total operating costs; very expensive regulatory-wise.

Is there a future for nuclear?
Yes in some regulatory scenarios in the IRP. There is still a lot to learn about nuclear since there have been no plants built in the last 30 years in the U.S. This creates a huge amount of risk in building nuclear power plants. Contractors and labor are inexperienced in new nuclear and it would be hard to finance at this point and the cost of materials (steel, concrete, etc.) are now at all-time highs.

FEEDBACK RECEIVED DURING THE PUBLIC MEETINGS

- Energy efficiency programs should be planned at higher levels. Appreciate NPPD's interest in renewables and efficiency, but need to have higher goals in order to get farther with more effort. Appreciate having gotten RMI input. Encourage NPPD to work through their wholesale customers to influence the end use customers concerning these new sources.

- The public utilities here have managed to avoid an RPS. The attitudes in this state are behind the times, whether utilities, energy office, lobbyist positions on legislators, etc – there is so much more going on in the states surrounding us.

- NPPD needs to have a program that helps small developers to get over the hump to install (e.g., a better net metering policy).

- NPPD needs almost to plan farther out than 20 years, considering how long units operate. Decisions need to be made now that will be good way past 20 years. We need to plan right for our children and grandchildren.

- Everybody should get their own solar panels on the roof of their home and a wind turbine in their back yard. Renewable is really the only way to go no matter the cost. After all, what is wealth if the planet dies? Really, you'd think more companies would donate labor and materials to make the U.S.A. all renewable energy.

- Need to look at a transmission map and wind map of Nebraska together. There is little or no transmission in the windiest areas of Nebraska.

- Based on 1/3 of Nebraska being windy at any given time, with NPPD's help, rural communities could start creating their own power and energy could be shifted back and forth between these communities. Rural communities do use less energy than urban.

- You have talked a little about conservation. NPPD should be doing a lot more about publicizing and educating the public on conservation.

- NPPD should have more community-oriented programs. Is free speaker willing to address community groups?

- It's frustrating that we have no national energy policy. How do we best utilize fuel to get best efficiency? Nebraska has an opportunity to lead this area. NPPD should partner with UNL to push and educate the public on this. We should utilize cogeneration better. We could also put together a plan to help our municipal partners utilize energy efficiency and cogeneration.

FEEDBACK FROM NPPD IRP WEB SITE (www.nppd.com/IRP)
(Received between December 3, 2007 and March 5, 2008)

- Here is a web site illustrating an idea I think would work well. If customers had some sort of system like this it would help with the increased generation requirements and the need to build new power plants & transmission (very expensive). The transmission is already in place for this type of approach. A combination of wind and solar would help offset the unreliability of just using wind. We have to pay to increase our generation, why not pay by installing systems at our customers' location. I think this would also be a very good PR thing and make the customer feel like they are making a difference.

- It is imperative that we move to "green technology" as soon as possible. We are not only in a bind economically, but we are on a disastrous collision with the

environment. Immediately - look to being an example to the rest of the nation, and use photovoltaic shingles on homes that agree to participate along with wind power and biomass power generation as a way to make sure that power is never in short supply. By making sure every home that will participate is generating electricity back into the power grid, the aging of the grid need never be a problem, and the only reason the power will ever go "out" will be a catastrophic disaster, and only then in the area it involves. Your homeowners and business customers will appreciate the opportunity to only pay the cost of maintaining the generation systems, and not paying for the extraction of fuels from the ground, however cheaply it is done. Nuclear power, while clean, is likely to go the way of fossil fuels, and be very rare and expensive someday. Better to plan on renewable resources now, as well as avoid the waste disposal question altogether.

- Good to see nuclear generation beyond pending uprate/extended license, and looking forward with additional capacity in the mix. Going to go back and review in more detail. Also, beyond the carbon footprint issues, there's plenty to support how challenging planning assumptions can be to determine: "These are tough times in the electric power business. The power industry must invest approximately $1 trillion by 2020 to upgrade and expand our electricity infrastructure – new power plants, efficiency programs, transmission, and distribution, environmental control technology – at a time when input costs are increasing dramatically. A recent assessment by the Brattle Group, a well-regarded consulting firm, shows that between 2004 and January 2007, the cost of steam generation plants, transmission projects and distribution equipment rose by 25-35 percent, compared to an 8 percent increase in the GDP deflator. The cost of gas turbines: Up by 17 percent in 2006 alone. Prices for wind turbines: Up by more than $400/kWe between 2002 and 2006. Prices for iron ore (are) up by 60 percent between 2003 and 2006, and for steel scrap up by 150 percent. Aluminum prices doubled between 2003 and 2006, and copper prices almost quadrupled. Much of this is driven by double-digit economic growth in China and India." Source: NEI Nuclear Notes Links: http://neinuclearnotes.blogspot.com/2008/01/nuclear-resurgence-and-reasonable.html

- Think NPPD should vigorously pursue the extension of your current nuclear plant license and apply for licensing for additional nuclear plants.

- Due to the increasing cost of traditional energy sources and the decreasing cost of renewables and the low cost of energy efficiency, I would like to see more emphasis on efficiency efforts and renewables. Both also offer a more secure energy system due to lower demand and diverse, local generation. And with legislation likely that will put a value on environmental impact traditional energy sources will only become more expensive. As for the issue of intermittent supply from renewables, there are many ways to get around that. For example, use wind and solar when available to generate hydrogen, then use the hydrogen in fuel cells. Or store energy by freezing water, heating salt, etc. It's being done elsewhere and it

can be done here. Keeping ahead (or at least keeping up with) the curve will bring jobs and benefit the local economies by keeping energy dollars at home.

- Forget renewable. The only reasonable solution is Nuclear.

- I would like to see NPPD repower Sheldon Station to be a viable resource into the future. This plant is well located and has a rich history of being reliable. It has a great staff

- It seems that in a state with so much sun and wind that we should be in the forefront of using solar and wind power. I could be proud of a state that would provide jobs in this way and make best use of our natural resources.

- Hi! Anything that can be done to help keep power costs down and also continue to have adequate power would be great. Thanks!

- I am a student at the University of Nebraska, and I am starting research for my Masters thesis which is a study of the use of photovoltaics in residential grid connected systems. I have read over the IRP, and I am involved with faculty currently involved in research with NPPD about lowering Nebraska's power needs. I am actually looking for any information you might have about the effect of that the different IRP scenarios will have on the cost of electricity per kWh for the average home owner in Nebraska. Even more general estimates the NPPD may have about where you see the cost of power going in the next 10 to 20 years. My overall goal is to compare the increasing cost of utility power with the decreasing cost of photovoltaic technologies to predict when home photovoltaic systems may become more feasible for homeowners in Nebraska to lower their energy needs from the utility in an environmentally friendly way. Any information would be a great help, and if you have other questions I would be happy to answer them.

- Dear NPPD, I would have loved to go to the public meetings, but scheduling was too tough for me. I had several thoughts, thank you for the opportunity to provide input. 1) NPPD needs to exert pressure on the REA's that are fighting net metering and other renewable energy initiatives by citizens. These activities by the REA lobbyists are absolutely shameful and the REA lobby needs to be brought under control. One can try to fight the future, but it only serves to have us unprepared when it arrives. (2) NPPD needs to work with C-BED projects better than it has and get PPA's out. Despite all the horn blowing on Ainsworth, we are dropping in national ratings like a stone with nothing on the boards regarding commercial wind projection. Finally, Old carbon coal seems to be the fuel of choice for NPPD. Our reliance on this fuel will be costly in years to come. NPPD needs to be able to obtain the green tags that will aid in protecting NPPD from carbon taxes and escalating rates. I suggest the greenhouse gases being spewed from these facilities be sequestered into algae grown in ponds located at the coal plants. Warm gases rich in CO2 will be able to provide rapid growth to second generation feedstocks to a struggling biodiesel industry in our state or be consumed by NPPD in low capacity peaking stations across the state where NPPD provides the fuel. This

process would go far toward the 'greening' of the old carbon processing facilities. Gas turbine exhaust from natural gas would work too. We are working on developing an algae pilot project in Lyons, Nebraska if you are interested in participating, otherwise information is out there. This needs to be looked at very seriously if NPPD is to reduce the coming impact of carbon taxes while developing a fuel that can provide firm power on demand or in an emergency. NPPD is an essential part of the Nebraska infrastructure and does a lot of great things for our state, unfortunately, seriously developing and supporting renewable energy (except biofuels) is not one of them. I hope this will change.

- I believe that you are charging everyone to waste power, make the first 1000kw the cheapest and raise the next 1000 and the raise the next 1000 higher, etc. I am going to lower my consumption 20% this year and 5% every year after for the next 5 years. Almost everyone I know can save if it will cost them more if they don't.

- I believe that electrical charges should be reversed, people that use little electrical power should get a break for their conservation, people that do not conserve should get a higher cost to get them to conserve. I know people that have a good income not even changing a light bulb because higher usage is so low cost. If your company really wants us to conserve then change the way you charge.

- I would recommend that NPPD investigate the following areas for energy saving opportunities: cogeneration on-site where significant amounts of heat are needed as well as electrical power; off-peak ice making & storage systems for air conditioning applications; and fuel cells.

Summary of the Independent Review of the IRP by the Nebraska Electric Generation & Transmission Cooperative, Inc.

Conclusions

- Based upon best available information, it appears that NPPD has carefully considered all the various uncertainties that might potentially impact its long-term energy requirements.
- NPPD has appropriately identified and considered the key variables most likely to impact NPPD's resource needs for the IRP study period.
- NPPD has generally made appropriate assumptions with respect to the ranges of variation of the key study variables.
- NPPD has developed a robust Integrated Planning Model that serves its resource planning needs effectively. Minor identified enhancements would improve the Model's output.
- While the Microsoft® Excel-based IRP model developed by NPPD is generally robust and suitable for the analysis being performed it is not a "full" probabilistic model.
  - Huron recommends that NPPD consider modifying two of the current calculation methods used in the Model.

    - Use distributions for "single-point" estimates throughout the model. (i.e. discount rate, inflation rate)
    - Vary the current calculation method by which the low, base, or high case scenarios are selected for certain inputs.
  - In Huron's opinion, implementing these two recommendations will make the Model "behave" like a probabilistic model and consequently will result in more realistic outcomes.
- There are no apparent deficiencies in NPPD's integrated resource planning approach, inputs and assumptions, resource modeling methodology or draft plan results that would adversely impact the NEG&T or its members.

NPPD Response

The minor identified enhancements relate to two suggested improvements for the probabilistic model, which NPPD will consider in future versions of the model.