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OPPD

Omaha Public Power District

2008 Integrated Resource Plan

2009-2023

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TABLE OF CONTENTS

1.0 INTRODUCTION AND PURPOSE 1

1.1 OPPD 15 YEAR PLAN 2
1.2 SENSITIVITY CASES 2
1.3 SCENARIO DEVELOPMENT 2
1.4 RENEWABLES 3
1.5 PUBLIC PARTICIPATION 3
1.6 OPPD IRP ON BEHALF OF MEMBER-BASED ASSOCIATIONS 3

2.0 EXECUTIVE SUMMARY 5

2.1 FUTURE PLANNED CAPABILITY – OPPD 15 YEAR PLAN 5
2.2 SUMMARY AND ANALYSIS OF RESULTS 6
2.3 RECOMMENDATIONS 9

3.0 FORECAST AND COST INPUTS 11

3.1 FORECASTS 11
Load Forecast *11*
Fuel Forecast *12*
Table 1 - U.S. Total Consumption of Natural Gas – All Sectors *13*
Capacity Market Forecast *13*
Table 2 - Capacity Purchase Pricing *14*
Wholesale Market Forecast *14*
General Economic Assumptions *15*
Table 3 – General Economic Assumptions *15*
Environmental Emissions Risk Forecast *15*
Ethanol Industry *16*
3.2 ACCREDITATION AND CAPACITY 17
3.3 CONSTRUCTION COST ESTIMATES 18

4.0 RENEWABLE ENERGY 19

4.1 OPPD RENEWABLE ENERGY POLICY 19
4.2 NEBRASKA LEGISLATION PASSAGE – LB 629, LB 65 AND LB 776 19
4.3 CURRENT OPPD RENEWABLE ENERGY PROJECTS 20
Request for Proposals – 80 MW Wind Energy *20*
NPPD Solicited C-BED Projects *20*
Valmont Prototype Wind Turbine *20*
Elk City Landfill Gas Facility *21*
NPPD Ainsworth Wind Energy Facility *21*
Fuel Cells and Distributed Generation *21*
4.4 RENEWABLE ENERGY RATE 22
4.5 POLICY ACTIONS NECESSARY, RENEWABLE GENERATION 22
4.6 NEBRASKA WIND STUDIES 23
4.7 RENEWABLE ENERGY PRODUCTION INCENTIVE 23
REPI Appropriations and Payments *23*
Table 4 - REPI Appropriation Summary *24*
Status of Renewable Energy Production Incentive - REPI *25*
Status of Production Tax Credits - PTC *25*
4.8 CLEAN RENEWABLE ENERGY BONDS (CREBS) 26
4.9 RENEWABLE ENERGY PORTFOLIO STANDARD 26
Potential Impact of RPS Mandate on OPPD *26*

5.0 ENVIRONMENTAL CONSIDERATIONS 29

5.1 1990 CLEAN AIR ACT AMENDMENTS....29
5.2 CAP AND TRADE PROGRAMS....30
Table 5 – Summary of Cap and Trade Emission Programs....*31*
5.3 EMISSION COMPLIANCE COSTS....32
5.4 SO_2 ALLOWANCES....32
5.5 NO_x EMISSIONS....33
5.6 MERCURY COMPLIANCE....34
5.7 PARTICULATES AIR POLLUTANT COSTS....34
5.8 NEW SOURCE PERFORMANCE STANDARDS....35
5.9 MULTI-POLLUTANT CONTROLS (MPC) CONSIDERATIONS....35
5.10 CARBON DIOXIDE EMISSION COSTS....36
Greenhouse Gas Intensity....*36*
Climate Stewardship Act (McCain-Lieberman)....*37*
5.11 MISSOURI RIVER – U.S. ARMY CORPS OF ENGINEERS MASTER MANUAL....38

6.0 SUPPLY-SIDE OPTIONS....39

6.1 SUPPLY-SIDE OPTION SCREENING....39
Combined Cycle Conversion of Cass County Station....*41*
6.2 FORT CALHOUN STATION LONG RANGE PROJECTS....41
Rapid Refueling....*41*
HP Turbine Uprate....*42*
MAPP Design Review Limits....*42*
6.3 CONVENTIONAL PULVERIZED COAL (PC) OPTION....42
6.4 COAL GASIFICATION/IGCC OPTION....43
Previous Demonstration Projects and Current Plans....*43*
Environmental Issues and Air Emissions....*43*
Table 6 – Comparison of IGCC Emissions to NC2 Emissions....*44*
Carbon Sequestration Opportunities....*44*
IGCC Conversion of Cass County Station....*44*
6.5 ADVANCED NUCLEAR OPTION....44
Estimated Nuclear Plant Costs....*45*
Drivers for Future Nuclear Units....*45*
6.6 WIND ENERGY OPTION....45
Key Issues and Cost Uncertainties....*46*
Cost Estimates....*46*

7.0 DEMAND-SIDE MANAGEMENT PROGRAMS....47

7.1 HEAT PUMP PROGRAMS....47
7.2 CURTAILMENT LOAD PROGRAMS....48
7.3 EMERGENCY AND STANDBY GENERATOR PROGRAM....48
7.4 REBUILD AMERICA PROJECT....48
7.5 ENERGY RESEARCH PARTNERSHIP....48
7.6 EVALUATION BY DSM STRATEGIC ISSUES TEAM....49
Table 7 – OPPD's Targeted DSM Programs....*49*
7.7 EPRI DSM MANAGER OPTIONS MODELED....50
Table 8 - Impact of Proposed EPRI DSM Manager Programs....*50*

8.0 THE OPPD 15 YEAR PLAN AND SUBOPTIMAL PLAN ANALYSIS....51

8.1 THE OPPD 15 YEAR PLAN....51
Table 9 – OPPD 15 Year Plan....*51*
Other Purchase and Sales....*51*
8.2 UNIT PARTICIPATION OPTION....52
Nebraska City Station Assumptions....*52*
8.3 RETIREMENT OF EXISTING UNITS....52

Table 10 – Age of Existing Baseload Units *53*
System Security *54*
8.4 DIVERSITY 54
8.5 RELIABILITY 54
8.6 DISPATCHABILITY 54
8.7 OTHER RISK FACTORS 55
8.8 SUBOPTIMAL SUPPLY-SIDE CASES 55
Suboptimal DSM Cases *55*
8.9 SUBOPTIMAL FUTURE BASELOAD OPTIONS 56
Table 11 – Suboptimal Options Analysis *56*
8.10 SUMMARY AND CONCLUSION 56

9.0 SENSITIVITY ANALYSIS 59

9.1 BENCHMARK CASE SENSITIVITY ANALYSIS 59
Table 12 – Load Growth, Wholesale Market, RPS and Carbon Sensitivity Case Analysis *60*
9.2 BENCHMARK SENSITIVITY CASES FOR CARBON PRICING 61
Table 13 – Carbon Pricing *62*
9.3 WIND ENERGY SENSITIVITY CASES 62

10.0 SCENARIO ANALYSIS 65

10.1 ALTERNATIVE SCENARIOS - EVOLVING WHOLESALE MARKETS 65
Market Dynamic Drivers *65*
End-state Scenarios *66*
Table 14 – Wholesale Market Scenarios and Market Drivers *67*
Table 15 – Wholesale Market Scenario Results *68*
10.2 MEAN GREEN SCENARIO 68
10.3 STATUS QUO SCENARIO 69
10.4 BET THE FARM SCENARIO 69

ATTACHMENTS 71

ATTACHMENT 1 – LOAD AND GENERATION CAPABILITY (SUMMER) 72
ATTACHMENT 2 – LOAD AND GENERATION CAPABILITY (WINTER) 73
ATTACHMENT 3 – LOAD AND CAPABILITY 74
ATTACHMENT 4 – ANNUAL SYSTEM PEAK DEMAND FORECAST 75
ATTACHMENT 5 – ANNUAL NET SYSTEM REQUIREMENTS FORECAST 76
ATTACHMENT 6 – FOSSIL FUEL FORECAST 77
ATTACHMENT 7A – ANNUAL WHOLESALE MARKET FORECAST 78
ATTACHMENT 7B – 2006 MONTHLY WHOLESALE MARKET FORECAST 79
ATTACHMENT 8 – ENVIRONMENTAL EXTERNALITY/ALLOWANCE TRADING FORECAST 80
ATTACHMENT 9 – SO_2 EMISSIONS AND ACID RAIN PROGRAM ALLOWANCES 81
ATTACHMENT 10 – NO_X ALLOWANCES UNDER A MULTI-POLLUTANT CONTROL STANDARD 82
ATTACHMENT 11 – HISTORICAL CO_2 EMISSIONS 83
ATTACHMENT 12 – SUPPLY-SIDE OPTIONS 84
ATTACHMENT 13A – BASELOAD SCREENING CURVE ANALYSIS 85
ATTACHMENT 13B – PEAKING/INTERMEDIATE SCREENING CURVE ANALYSIS 86
ATTACHMENT 13C – BUSBAR COST – FUNCTION OF CARBON TAX 87
ATTACHMENT 14 – FT. CALHOUN EXPECTED POWER UPRATE CAPACITY GAINS 88
ATTACHMENT 15 – SUBOPTIMAL CASES 89
ATTACHMENT 16 – SENSITIVITY CASES 90
ATTACHMENT 17 – WIND ENERGY CASES 91
ATTACHMENT 18 – SELECTED CASES 92

APPENDIX A – GENERATION TECHNOLOGIES 93

ADVANCED NUCLEAR 93

ADVANCED BATTERIES 93
COMBUSTION TURBINE 94
COMBINED CYCLE 94
LM-6000 COMBUSTION TURBINE 94
COMPRESSED AIR ENERGY STORAGE 94
CONVENTIONAL PULVERIZED COAL 95
INTERNAL COMBUSTION (DIESEL) 95
LANDFILL GAS TO ENERGY 95
FLUIDIZED BED 95
FUEL CELLS 96
INTEGRATED GASIFICATION COMBINED CYCLE 96
INTEGRATED GASIFICATION COMBINED CYCLE W/ CO_2 CAPTURE AND SEQUESTERING 97
MUNICIPAL SOLID WASTE 97
PUMPED STORAGE 97
SOLAR CENTRAL RECEIVER 97
SOLAR PHOTOVOLTAIC 98
WIND 98
WOOD 98

1.0 Introduction and Purpose

Integrated Resource Planning (IRP) or "Least-Cost Planning" can be defined as a process by which the optimum combination of a full range of alternatives including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and heating and cooling applications, and renewable energy resources are selected to meet the forecasted demand at an acceptable level of reliability and adequacy, ensuring environmental preservation, and at the lowest possible cost to the customer. OPPD has always valued a diverse fuel mix for generating electricity as a means of promoting reliability and affordability of its product.

The integrated planning process must encompass the multitude of variables, both quantitative and qualitative, which impact utility operations. From a quantitative standpoint, computer modeling (Strategist) designed specifically for least-cost planning provides the necessary up front economic analysis. The qualitative nature of the framework provides a list of options which best fit the utility's mission given its financial, legal and regulatory constraints. The final plan must be flexible enough to respond to changes in the business environment.

The 2008 IRP considered a comprehensive list of supply-side resource technologies expected to be available during the fifteen-year study period of 2009-2023 to develop the OPPD 15 Year Plan. These options include capacity purchases, a power uprate project at Ft. Calhoun, conventional pulverized coal, simple and combined cycle combustion turbines, aero-derivative turbines, internal combustion engines (diesel), fluidized bed, coal gasification (IGCC) and advanced nuclear. Renewable options considered include wind turbines, landfill gas to energy, solar photovoltaic and thermal, municipal solid waste, bio-diesel, switch grass, fuel cell, whole tree, and wood retrofit technologies. Storage technologies such as pumped storage, compressed air energy storage, and batteries are considered.

The 2008 IRP considered four demand-side management (DSM) technologies which are air conditioner (a/c) cycling, a/c set-back thermostat, a/c cleaning, and a high efficient, commercial lighting program. During 2007 OPPD established the division for Sustainable Energy and Environmental Stewardship. The objectives of this division include analyzing a comprehensive list of DSM technologies options and narrow these to those options that will be best suited for OPPD. The IRP process can use the cost and performance criteria of these DSM options.

Integrated Resource Planning is an ongoing process where decisions are made on current expectations and longer term plans are altered as these expectations change.

1.1 OPPD 15 Year Plan

After the completion of Nebraska City Unit 2, the OPPD 15 Year Plan calls for a power uprate at Ft. Calhoun Station which will make available 75 MW of baseload capacity at system peak load. This uprate will be available after the 2012 fall outage. A new high pressure rotor will be installed which is designed to handle more steam. The next capacity addition after the Ft. Calhoun uprate will be a project to convert the existing Cass County simple cycle gas turbines into combined cycle operation by adding a heat recovery steam cycle creating 530 MW of capacity at Cass County Station (an increase of 210 MW). The plan adds a simple cycle CT at Cass County in 2021. The 15 year expansion plan through 2023 adds a baseload coal unit in 2023, presumably Nebraska City Station Unit 3.

1.2 Sensitivity Cases

The 2008 IRP uses sensitivity cases to demonstrate how resources within the OPPD 15 Year Plan are likely to change by varying the model's input parameters. In these high-level sensitivity cases only single variables are changed in each scenario. Some of the sensitivity cases are not necessarily plausible in the future, but they are useful for demonstrating the magnitude of change that would be required to significantly impact the viability of the OPPD 15 Year Plan. Key uncertainties that impact future power supply decisions include future environmental regulations and legislation, power supply costs, coal and natural gas costs, and load growth. These will have a significant impact on the final resource selection and total cost. Given these uncertainties, it is prudent to consider a number of different sensitivities in the IRP process. Sensitivity cases are analyzed in Section 9 and the results of the sensitivity cases are shown in Attachment 16.

1.3 Scenario Development

A variety of scenarios were developed and analyzed in the 2008 IRP. Scenario development involves the iterative development of plausible alternative views of the future given different economic, regulatory and technological driving forces. Generally, the longer the time frame the greater the scenario bounds, or breadth of plausible futures. Scenario development is a proven tool to better anticipate and respond to future risk and opportunities. These scenarios are intended to provide a framework for further analyzing strategic issues and options. Strategic issue teams within OPPD provide strategic recommendations to senior management to help ensure that appropriate strategies are in place to mitigate risks and capitalize on opportunities.

An OPPD initiative to study potential evolving markets selected alternative scenarios of these markets and outlined the forces driving each of these scenarios. These scenarios were developed based on the changing industry market structure and dynamics. Three scenarios were analyzed in the 2008 IRP and are discussed in Section 10.

1.4 Renewables

Wind energy is the most economical form of expandable, renewable electrical generation available to OPPD. Landfill gas generation is actually lower cost than wind, but OPPD is already utilizing all the available methane gas at the Douglas County landfill through the operation of the Elk City Station. Costs for thermal and photovoltaic solar, various biomass and biomass co-firing technologies are acknowledged in the IRP plan development. The costs of these technologies are evaluated in a screening process. Their high costs remove them as viable resource choices. This doesn't prohibit OPPD from installing small scale renewable generation of various forms to study their effectiveness. The 2008 IRP considers wind options in 100 MW, wind farm, increments. These installations do not prove to be economical and are not part of the OPPD 15 Year Plan. The cost for wind is based on actual projects under development in the Midwest region. As with costs for all generation technologies, wind costs have escalated. The recent wind cost increases, moves wind to a marginally unaffordable level in the 2008 IRP.

Additional wind may be required if a Nebraska or federal Renewable Portfolio Standard (RPS) is enacted. A high and very high carbon tax scenario leads to the need of 100 MW increments of wind in the 2008 IRP. There are many uncertainties surrounding the development of large-scale wind energy facilities. These uncertainties include production plant capital costs, transmission costs, operating and wind integration costs, siting, expected capacity factors, wholesale market prices and the availability of incentives. Renewable energy is discussed in Section 4. The 2008 IRP extensively analyzed a variety of wind energy sensitivity cases. These cases are discussed in Section 9.3, and the results are shown in Attachment 17. Nebraska wind facility financing may increasingly come from financial investors instead of directly by public power, though it is expected a major portion of the electrical energy generated from these wind farms would be purchased by Nebraska public power entities. Nebraska utilities are currently evaluating infrastructure expansion requirements and system operational issues to Nebraska's electrical system issues related to large scale wind installations within the state.

1.5 Public Participation

A formal public participation stage was part of the development of the 2007 IRP. As the IRP is a public document OPPD customer-owners and the public at-large are invited to offer their input on the planning process on an on going basis. All OPPD Board meetings are open to the public and the public can contact OPPD Corporate Communications offices directly. The next time the OPPD will formally enter a public comment period, similar to the process performed in 2007, will be for the 2011 IRP. Please refer to the 2007 IRP document to get a synopsis of public comments provided at that time.

1.6 OPPD IRP on Behalf of Member-Based Associations

The OPPD 2008 IRP meets federal regulations on the behalf of four Member-Based Associations (MBA). These MBAs are full requirements customers of OPPD's and also

receive firm capacity and energy obligations from the Western Area Power Administration. The MBAs include Peru State College, City of Syracuse, City of Tecumseh and the University of Nebraska at Omaha. The governing body of these MBAs must approve the OPPD 15 Year Plan and IRP.

2.0 Executive Summary

The 2008 IRP is the result of a process in which the optimum combination of a full range of alternatives including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and heating and cooling applications, and renewable resources are selected to meet the expected energy and demand needs of OPPD's customer-owners. Resource options are selected based on an acceptable level of reliability and adequacy; environmental preservation and responsibility; and the lowest possible cost to OPPD's customer-owners. The selection process must take into account necessary features for system operation such as diversity, reliability, dispatchability and other risk factors. In development of the IRP demand and supply resources must be treated on a consistent and integrated basis.

The OPPD 15 Year Plan is a combination of customer load and generation programs with additional generation capacity. Existing customer load curtailment and leased generation capacity programs are expected to reduce the peak demand by approximately 56 MW in 2009 and remain at this level throughout the planning period. A 663 MW Nebraska City Unit 2 will be completed in May 2009 with OPPD's share of 331.5 MW and 331.5 MW sold on long-term participation power agreements. Based on the current load forecast, OPPD may need additional capacity in the summers of 2011 and 2012. In the short-term, additional capacity can be purchased. 75 MW of additional baseload generation will be available from Ft. Calhoun in 2013. Capacity and intermediate capacity factor, energy needs, will be met by combined cycle operation of Cass County in 2014. OPPD's Load and Generation Capability is shown in Attachment 1.

2.1 Future Planned Capability – OPPD 15 Year Plan

The resources required to meet the forecasted OPPD retail load growth for the period 2009-2023 are in the OPPD 15 Year Plan and include:

- Approximately 56 MW of existing curtailable load and customer-owned generation. This is forecast to remain at this level throughout the planning period.
- An Extended Power Uprate at Fort Calhoun Station upon completion of the 2012 fall outage by replacing the high pressure rotor while increasing the plants thermal capacity. The uprate is expected to increase the July and August rating by 75 MW. The remaining months' increases will be 79 MW. This capacity addition allows OPPD to maintain a diversity in fuel supply as nuclear fuel will continue as a key contributor in meeting OPPD's retail load.
- Conversion of Cass County Station's two existing combustion turbines into combined cycle operation in 2014 where the exhaust heat from the existing simple cycle units are input to a newly installed steam cycle, generating 210 MW additional capacity to achieve 530 MW total capacity at Cass County Station.
- Peaking capacity purchases in 2011, 2012, 2019 and 2020.

- A 160 MW combustion turbine in 2021.
- The next baseload generator is needed in 2023 this would be a 660 MW coal-fueled Unit 3 at Nebraska City Station, similar to Unit 2, it is recommended half the output be sold to participants under long-term agreements.

2.2 Summary and Analysis of Results

The current OPPD 15 Year Plan includes a new baseload coal unit at Nebraska City Station in the last year, 2023. Further capacity and energy requirements are met by a Ft. Calhoun power uprate, the conversion of Cass County Station to combined cycle, and, later, an additional simple cycle combustion turbine. Capacity purchases in certain summer seasons will also be required. Upcoming annual IRP evaluations will continue to weigh the viability of Nebraska City Unit 3 based on 4 key considerations. The OPPD customer-owner rate impact of adding a new baseload unit by 2023 may be too great to bear. The OPPD sustainable energy and environmental stewardship initiative has potential to slow growth in retail load demand not yet accounted for in the load forecast; delaying by one or two years the need for a baseload unit. The uncertainty of knowing the type of regulatory structure carbon will be under upon plant completion. The increasing politicization of the approval process to build coal plants makes certainty of receiving approval a significant risk.

The uprate at Ft. Calhoun is economically viable especially given the rising capital costs for ground-up construction of baseload generation. Nuclear generation has the advantage of not producing greenhouse gases. The conversion of Cass County Station Units 1 and 2 to combined cycle along with the addition of a simple cycle combustion turbine unit in 2021 will be fueled by natural gas. Longer term natural gas forecasts have moderated. The capacity additions at Cass County are lower cost capital commitments than a baseload coal (pulverized or IGCC) or nuclear unit and their economic viability will ultimately rest on the future cost of natural gas.

The cost to delay Nebraska City Unit 3 outside the 15 Year Plan, delay to year 2024, is around 0.2% of the total 30 year simulation NPV cost. Additional analysis was performed to determine the cost of installing a 300 MW share of an advanced nuclear unit, or an IGCC unit to meet this baseload capacity requirement. The results show that the NPV cost of an advanced nuclear unit would be $346 million (3.5%) more than adding a pulverized coal unit and an IGCC unit would be $85 million (0.8%) more. These cases are discussed in Section 8.8, and the results are shown in Attachment 15. Future environmental regulations, power supply costs, fuel costs, new legislation and load growth will have a significant impact on the final resource selection and total cost.

Sensitivity analyses determine the impact of changing key data assumptions on the OPPD 15 Year Plan. The Ft. Calhoun power uprate is needed in the vast majority of sensitivity studies. Only a limited number of sensitivity cases remove the uprate from the plan

including a low load growth forecast, very low natural gas prices and a case with very low wholesale market prices. The combined cycle conversion at Cass County is fairly robust to the sensitivities analyzed. The low load growth sensitivity of 1% per year, takes the conversion out of the OPPD 15 Year Plan. Specific sensitivities will delay the conversion one year or two years to 2015 or 2016, respectively. These include wind farms to meet a 15% renewable portfolio standard (RPS), DSM peak shaving projects of 40 to 55 MW, and implementation of 100 MW of storage technologies, battery or CAES are storage options studied. The results of these sensitivity cases are shown in Attachments 16 and 17, and they are further discussed in Section 9.

Wind farms, sized at 100 MW in nameplate rating, are an option available to the optimization analysis. No 100 MW wind farms are chosen in the OPPD 15 Year Plan. In the IRP model, wind energy facilities are expected only to be considered in higher capacity factor wind areas. This annual capacity factor is 40%. These high wind areas are thought to be located outside OPPD's service area, e.g. north-central Nebraska. There are also significant issues and uncertainties to consider before building large-scale wind energy facilities. Wind energy merits ongoing study as part of a comprehensive OPPD sustainable energy strategy. Cost of wind has risen in the last year to a point where it is above the average wholesale market price. In IRP optimization analysis several 100 MW wind farms are more likely as their levelized cost is near or below the wholesale market price. Some portion of wind energy can then be sold to the market, instead of requiring low cost generation units to lower output when wind energy is being generated. Thus, the feasibility of a wind energy facility is very sensitive to changes in wholesale market prices as well as wind generation component costs. Wholesale market prices tend to follow natural gas costs—and have been very volatile and difficult to predict. The results of the alternative wind cases are shown in Attachment 17, and wind energy is further discussed in Section 4.

An OPPD initiative to study potential evolving markets identified alternative scenarios for evolution of the wholesale market and outlined the forces driving each of these scenarios. These scenarios were developed based on the changing industry market structure and dynamics. In the 2008 IRP these scenarios were further developed, quantified, and modeled. The Mean Green scenario includes increased costs for fossil fuel emissions and natural gas prices and a 15% renewable portfolio standard (RPS) as some key variations to base assumptions. A lower load growth forecast is also assumed in the scenario. The lower growth in retail demand and energy requirements leads to the next baseload unit to be installed in 2035 - a nuclear unit. Pulverized coal-fired generation is not allowed in the Mean Green scenario. The Mean Green scenario has a NPV 20.2% lower than the OPPD 15 Year Plan. The Ft. Calhoun power uprate is not in the plan. The Status Quo scenario has no carbon tax implemented during the study years and is the only significant variation from the benchmark. This scenario demonstrates the large impact a carbon tax has. The absence of a carbon tax maintains the pulverized coal baseload option. The Status Quo does not include the Ft. Calhoun power uprate and adds Nebraska City Unit 3 in 2021. The Bet the Farm scenario is the scenario that the evolving market issue team put forth as the most likely scenario. Increased conservation and the addition of 200 MW of wind delays the next baseload unit until 2033 and eliminates the Fort Calhoun

power uprate from the expansion plan. All future generation requirements before 2033 are met by gas-fired generation. These scenarios and models are discussed in Section 10, and the results are shown in Attachment 18.

Among the largest uncertainties when planning for future generation are changes in environmental regulations. Given the political nature of these types of regulations, predictions are difficult. To remain in operation, it is likely existing coal-fired power plants in the U.S. will need to have multi-pollutant control (MPC) equipment in place. In the meantime OPPD must continue to meet regulatory requirements as set under the Clean Air Act Amendments (CAAA). 2008 saw the vacature by court action of two key EPA programs which were to take effect in 2009 and 2010: the Clean Air Mercury Rule (CAMR) and the Clean Air Interstate Rule (CAIR). It is likely that carbon dioxide emissions will be regulated within the fifteen-year timeframe addressed in the 2008 IRP. Given the uncertainties and multiple legislative proposals addressing climate change, it is very difficult to quantitatively assign costs to CO_2 emissions. However, it is prudent to include a CO_2 cost in the IRP. For the 2008 IRP OPPD has concluded that $5/ton (beginning in 2012) increasing at a steady annual rate until reaching $23/ton in 2032 be used for a carbon tax. The carbon tax is a cost for each ton of CO_2 emissions above pre-defined allowances. This estimate is a reasonable estimate to use in the 2008 IRP and this assumption is used by Ventyx in “Midwest Regional Outlook, Spring 2008”. In addition to the base assumption for a carbon tax, the 2008 IRP also considered sensitivity cases as shown in Attachment 16.

The 2008 IRP Strategist model is used in evaluating data contained in the OPPD DSM Strategic Plan. Key team members at OPPD are familiar with the tools Strategist lends to DSM economic evaluation. With this in mind the team can better formulate potential DSM program data such as load adjustments, participation rates and costs to fully take advantage of Strategists’ computational features. OPPD will use Strategist as a fully integrated resource and DSM evaluation tool. The DSM team has developed business plans for a number of DSM plans impacting residential and commercial and industrial customers. DSM programs should be pursued that are tailored to provide value to OPPD’s customers, lower the cost of electricity and which are beneficial to the environment. The implementation of these options must take into account the ability to verify energy savings through energy efficiency and the projected durability for such savings measured over time. The results of four DSM cases are shown in Attachment 15, and DSM programs are further discussed in Section 7.

Public participation in the development of the IRP is scheduled to occur no later than the year 2011 as part of the process of creating the 2011 IRP and the OPPD 15 Year Plan.

2.3 Recommendations

Based on the results of the 2008 IRP, the following recommendations are made:

1. Place the OPPD 15 Year Plan into the OPPD corporate operating plan.
2. Continue to closely monitor the future cost of CO_2. This is one of the greatest uncertainties facing OPPD, and has the potential to add tens of millions of dollars to annual operating costs and may change the OPPD 15 Year Plan. In the 2008 IRP the base assumption for evaluating future year costs included a $5/ton carbon tax beginning in 2012 increasing to $23/ton in 2032.
3. Continue to monitor project cost estimates to replace the high pressure turbine at Fort Calhoun which will result in additional 75 MW capacity available for the summer 2013. This option is part of the OPPD 15 Year Plan. This addition of approximately 672 GWh of annual electrical generation will continue Ft. Calhoun Station's contribution to OPPD's fuel diversity as OPPD's retail load continues to grow.
4. Continue to evaluate the economic feasibility of converting Cass County Station Units 1 and 2 to combined cycle operation by the addition of a steam cycle. The OPPD 15 Year Plan places this 210 MW of capacity in service in May 2014. Construction would need to begin in 2010.
5. Continue to study options for OPPD's next baseload unit requirement. These options include a conventional pulverized coal unit or a share of an advanced nuclear unit or an IGCC unit. This baseload requirement is projected in 2023.
6. Continue to monitor and evaluate further opportunities to increase the use of renewable energy that is cost-effective and further develop a sustainable energy strategy. The 2008 IRP base case wind option is 100 MW wind farms at 40% capacity factor available in multiple years. Due to increased costs of wind turbines and towers, wind is not part of the OPPD 15 Year Plan. Sensitivities show a slightly lower equipment cost makes wind an affordable option. Thus, select wind options will merit in-depth economic evaluation, possibly bringing more wind into OPPD's portfolio in a shorter time.
7. Determine the impacts of OPPD joining the Southwest Power Pool (SPP) on the system model used in IRP development. These include wholesale market prices and OPPD generating unit deliverability capability.
8. Closely monitor OPPD's SO_2 allowances under the Acid Rain Program. Burning coal from projected coal mine sources in the 2009 – 13 coal contract, leads to an SO_2 deficit condition as early as 2010 or 2011. OPPD will have to either reduce emissions or buy allowances from the SO_2 market to meet regulations.

9. Closely monitor efforts to expand the regional transmission grid which may occur as national strategic initiative to curb greenhouse gas emissions focus on the US Midwest as a source for large scale wind produced electricity.

10. Continue to reduce peak load through cost-effective DSM programs such as the curtailable demand program; conduct a thorough evaluation of existing DSM programs and identify potential new programs which can be modeled in Strategist; and further evaluate emerging initiatives that increase the use of energy efficiency programs in lieu of adding generation (such as the standards set forth in the Energy Policy Act of 2005 and the 2007 Energy Independence and Security Act). As programs are implemented, methods of verifying energy savings and the projected durability of such savings over time must be verifiable.

11. Continue to monitor legislative, regulatory, legal and environmental issues that impact the existing generating fleet and new resource options. These issues include multi-pollutant control legislation, Missouri River flows, carbon/greenhouse gas legislation, renewable portfolio standards, SO_2 allowances, and promulgation of rules by the EPA under the CAAA.

The OPPD load and generation capability incorporating the recommendations above are shown as Attachments 1, 2, and 3.

3.0 Forecast and Cost Inputs

Integrated Resource Planning or "Least-Cost Planning" can be defined as a process that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and heating and cooling applications, and renewable energy sources by which the optimum combination of these alternatives are selected to meet the forecasted demand, at an acceptable level of reliability and adequacy, ensuring environmental preservation, and at the lowest possible cost to the customer. Lowest possible cost includes utility costs to provide electric service, customer costs for demand-side management programs, and societal costs for environmental preservation.

This integrated process must encompass the multitude of variables, both quantitative and qualitative, which impact utility operations. It must take into account necessary features for system operation, such as diversity, reliability, dispatchability and other risk factors. From a quantitative standpoint, computer modeling designed specifically for least-cost planning provides the necessary up front economic analysis. These models provide a comprehensive and fair assessment of supply- and demand-side options. The qualitative nature of the framework provides a list of options which best fit the utility's mission given its financial, legal, and regulatory constraints. The final plan must be flexible enough to respond to changes in the business environment including: load impacts due to deregulation, cost and availability of fuel, cost and performance improvements in mature and emerging technologies, economic up- and down-turns, and environmental regulations.

3.1 Forecasts

The IRP models are based upon inputs and forecasts from many of OPPD's Divisions. The process of preparing and gathering these forecasts is an integral part of the IRP process.

Load Forecast

The fundamental elements required in developing an IRP are the system peak demand and energy forecasts. The 2009-2023 Peak Demand and Net System Requirements forecasts, including conservation DSM programs (residential energy conservation and commercial HVAC), are listed in Attachments 4 and 5. Both the peak system demand and net system requirements forecasts have increased in the long-term, relative to last year's forecast. This increase is driven by higher industrial demand, a large part of that growth coming on-line through the summer of 2009. The current peak system demand forecast has a 15-year growth rate of 1.9%, versus 1.8% in the previous forecast. The Net System Requirements (energy) Forecast has also increased relative to last year's forecast. The current Net System Requirements forecast is for a growth rate of 1.6%, versus 1.5% in the previous forecast.

To study the impact of possible marketplace changes, Pricing and Forecasting Services

Department created a base forecast. Residential and commercial sales forecasts were developed by using econometric models for average use (sales/customers) and the number of customers. The average use model specifications use the Statistical Adjusted End-Use (SAE) modeling technique. In this method, saturation and efficiency trends were developed using Energy Information Administration data. OPPD energy planning studies and economic trends are incorporated into econometric model framework to capture appliance trends in the context of the statistical model. The industrial forecast was created by developing econometric models and combining these models with the individual customer forecast for the largest customers with input from the OPPD Account Executives. Upon the completion of the class forecasts, the OPPD total monthly forecast was developed as the sum of all the rate classes. As a final step, the monthly system forecast were transformed to an hourly forecast using the OPPD class load shapes. The OPPD load shapes along with the energy forecast are then used to develop a system hourly forecast which includes the OPPD system peak. Then the base hourly load forecast is broken out amongst the rate classes; residential, small general service, large general service, towns and lighting.

Fuel Forecast

The Fuels Division provides forecasts for uranium, coal, natural gas, and fuel oil. Attachment 6 shows the fuel cost projections.

During 2008 OPPD entered a 5 year coal contract for a portion of coal requirements for the years 2009 -2013. A contract for coal rail services is also entered for these 5 years. The expected increases in cost of delivered coal are becoming reality. Contract coal in 2009 will cost around $2.00/MMBtu delivered. Over the 15-year forecast period, coal prices are expected to moderate slightly from 2009 levels, but will not return to the traditional sub $1.00/MMBtu levels experienced for so many years. During the 2009-2013 contract period about 50% of coal requirements will be purchased on the spot market. Spot coal is expected to cost in the $2.00/MMBtu range through 2009 as well. A weighted average of contract coal costs and spot market costs are used to determine the cost of coal at Nebraska City Station and North Omaha Station (see Attachment 6). The costs shown in Attachment 6 represent the delivered cost of coal, including both the coal cost and rail costs. All coal deliveries come from mines located in the Powder River Basin of Wyoming.

In recent years natural gas price volatility has been driven by weather, storage levels, consumer demand and production levels. In mid-2008 gas prices increased as petroleum cost rose to historic levels. In the midst of an economic downturn taking hold in the 3rd quarter, 2008, natural gas pricing has softened considering gas prices typical rise entering the North American winter heating season. Natural gas prices are projected to remain near $8.00/MMBtu (nominal $'s) through 2009. Strong U.S. natural gas production came as somewhat of a surprise. LNG imports contributions to the U.S. domestic market seemed to be gaining a foothold in 2007 yet have fallen to miniscule levels in 2008. Shut in production during the 2008 hurricane season had very slight impact on the market. With stronger than expected domestic production, the impacts expected a few years ago from LNG may take longer to materialize; beyond 2010 instead of as of 2010. In the long-term, an increase in demand from electric utilities for natural gas is also expected to result in upward pressure

on prices. Nationally, most new electric generation is expected to be fueled by natural gas. Interestingly, U.S. total natural gas consumption in all sectors has been flat since 2001-2007. Rising prices have most likely kept this demand flat and probably demonstrates supplies are being stretched. Year ending August 2008 does show around a 4 – 5% increase over previous annual use. The dramatic spike in oil prices in mid-2008 probably led to some fuel switching to natural gas

Table 1 - U.S. Total Consumption of Natural Gas – All Sectors

(Source: EIA)

12 Months: September – August	Natural Gas Consumption (Billion Cubic Feet)
2001 – 2002	22,500
2002 – 2003	22,749
2003 – 2004	22,243
2004 – 2005	22,317
2005 – 2006	21,517
2006 – 2007	22,588
2007 – 2008	23,597

For the 15-year forecast period covered by the 2008 IRP, natural gas will come down slightly in real terms, considering the general inflation rate of 1.9%. Forecasted natural gas costs (generation and start-up) are based on an interruptible rate for both Sarpy County Station and North Omaha Station. The source of this gas is from the Metropolitan Utilities District. OPPD obtains interruptible natural gas for Cass County Station from other suppliers. Fuel oil is the only fuel at Jones Street Station and is a secondary fuel at the Sarpy County Station. Due to the expense to generate electricity from oil, Jones Street Station is the last large OPPD unit to be dispatched. Interruptions in natural gas supply at both Sarpy County and Cass County Stations may necessitate operating Sarpy County Station on fuel oil.

Capacity Market Forecast

A considerable amount of new generation in the region has contributed to lower capacity prices. It is expected that over 92,000 MW of new generating capacity will have entered the Midwest markets between 2000 and 2012. Although much of this new capacity is located near major population centers, there are still some transmission congestion concerns in certain areas. As shown in Table 2, in recent years, firm capacity prices have decreased in the region. They are forecast to remain stable in the near future.

Table 2 - Capacity Purchase Pricing
($/kW-season)

YEAR	2002 IRP (2001 $)	2003 IRP (2003 $)	2004 IRP (2004 $)	2005 IRP (2005 $)	2006 IRP (2006 $)	2007 IRP (2008 $)	2008 IRP (2009 $)
2001	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2002	18.00	N/A	N/A	N/A	N/A	N/A	N/A
2003	18.00	15.00	N/A	N/A	N/A	N/A	N/A
2004	18.00	15.00	15.00	N/A	N/A	N/A	N/A
2005	N/A	15.00	15.00	15.00	N/A	N/A	N/A
2006	N/A	15.00	15.00	15.00	15.00	N/A	N/A
2007	N/A	N/A	15.00	15.00	15.00	15.00	N/A
2008	N/A	N/A	N/A	N/A	15.00	15.00	15.00
2009	N/A	N/A	N/A	N/A	N/A	15.00	15.00

Wholesale Market Forecast

The forward price expectations are derived from market forecasts obtained from Ventyx (formally Global Energy Decisions) plus some additional risk adjustments that lower the forecast. Natural gas prices are the single most important determinant impacting wholesale power prices. Therefore, one can assume that the lower a given forward price forecast, the lower the gas prices in the forecaster's assumptions. Future generation additions are implicit in Ventyx's forward price curves. The pricing of this energy reflects the supply and demand balances in the entire Midwest region. These prices are based on the incremental fuel cost of the generating units which provide this energy, which are usually natural gas-fired combustion turbines or combined cycle units during on-peak hours.

The Department of Energy had forecast earlier this decade that 36,000 megawatts of new coal-fueled power supply would come online in the U.S. by 2008. Instead, only about 5,000 megawatts of supply were built. In the last two years, 76 coal plant proposals have been abandoned or postponed, according to the advocacy group Source Watch. In 2007, alone, that amounted to more than $45 billion in shelved projects, the group claims.

Historically, OPPD has sold large amounts of on- and off-peak interchange energy (non-firm power) to neighboring utilities. In recent years, about $100 million, or about 20% of

General Business Revenues, have come from wholesale market revenues. Annual wholesale market forecasts for non-firm energy are shown in Attachment 7A, and 2009 monthly prices are shown in Attachment 7B.

General Economic Assumptions

The accurate forecasting of economic assumptions such as inflation and interest rates do impact capital investment decisions. Table 3 lists the general economic assumptions used in developing the forecasts for the 2008 IRP.

Table 3 – General Economic Assumptions

Unit Life	30 Years
Inflation Rate	1.9%
Interest Rate	5.6%
Discount Rate	7.0%
A&G Cost (% of O&M)	5%
Insurance	1 $/kW-yr

Forecasted annual inflation which is the normal year-to-year escalation in the cost of goods and services required by OPPD is 1.9%. This is a reduction from 2.0% used as the assumption in the 2006 and 2007 IRP. The annual interest rate which is OPPD's cost of securing long-term financing (i.e., the interest paid to bondholders) including the cost of financing has decreased slightly from 5.7% to 5.6%. Inflation and interest rate forecasts are based on the March 2008 Global Insight 10-year forecast. The discount rate is the marginal opportunity cost associated with the capital secured, and it is used to equate streams of revenue requirements to a present value equivalent (i.e., time value of money).

In developing the least-cost power supply expansion plan, in most cases a life of 30 or 40 years is assumed and the capital costs are amortized over that period. O&M costs include operating labor, total maintenance, and overhead components. The total annual expenditure for O&M costs is normally available for existing units and can be estimated for new units. However, accurately allocating the overhead components such as administrative and general (A&G) costs and insurance costs is difficult: A&G costs are allocated based on 5% of O&M costs and an additional 1 $/kW-yr is added for insurance costs.

Environmental Emissions Risk Forecast

Among the largest uncertainties when planning for future generation is change in environmental regulations. Future environmental regulations could potentially dictate the technology chosen for a baseload power supply resource. Significant reductions in emissions limits, or establishment of taxes or limits on carbon emissions would result in a

nation-wide shift from pulverized coal towards other power sources such as renewables, nuclear, natural gas-fired combined cycle and IGCC. (Please see Section 5 for a discussion of environmental considerations.) Scenarios were developed to show how changes in environmental emission costs change the cost of the OPPD 15 Year Plan or the least-cost generation option selected. The assumptions for increased environmental costs are shown in Table 13.

As discussed in Section 5, it is likely that carbon dioxide emissions will be regulated within the OPPD 15 Year Plan. The 2008 IRP assumes an increasing carbon tax beginning in 2012. The magnitude of the CO_2 regulation risk faced by OPPD, and its customer-owners, depends on the carbon intensity of the generation resource portfolio. Portfolios with a heavy emphasis on carbon emitting resources face the risk of increased power supply costs. OPPD believes that it is prudent to include cost for CO_2 emissions in the IRP base case model.

There is also some uncertainty regarding the costs to remove SO_2, NO_X, and mercury from plant emissions. It seems likely that all coal-fired power plants in the U.S. will be required to install Multi-Pollutant Control equipment in their facilities in the next 5-10 years.

OPPD is performing on-going studies on Nebraska City Unit 1 related to pollution control requirements that fall under the EPA's regional haze rule. Current results of dispersion modeling demonstrate Nebraska City Unit 1 does not impact regional haze with its current emission controls. If desulfurization equipment in the form of a scrubber is not installed at Nebraska City Unit 1, OPPD must pay careful attention to current projected surplus of SO_2 allowances and in what future year additional allowances may be needed. (see Attachment 9). In recent years, the price of SO_2 allowances has been very volatile. During the 2nd and 3rd quarters of 2008 the cost of SO_2 allowances declined in conjunction with the EPA's Clean Air Interstate Rule being vacated by court order. The national caps on SO_2 emissions under the Clean Air Act are 9.48 million tons of SO_2 per year for 2001-2009, and 8.95 million tons of SO_2 per year from 2010 forward. SO_2 allowances will be sold in the same market regardless of whether from Acid Rain or the more recent Clean Air Interstate Rule (CAIR) requirements.

Ethanol Industry

The ethanol industry is poised for large growth in Nebraska and the Midwest as the U.S. strives for greater energy independence from foreign supplies. The incentives within the Energy Policy Act of 2005 towards ethanol will further drive this growth. The Nebraska Ethanol Board lists 24 operational ethanol plants in the state with 3 under construction, with the last of these 3 to be completed by the end of 2009. However the weight of recessionary pressures in the 4th quarter 2008 and beyond may stall proposed ethanol development. The Cargill facility in Blair which OPPD provides electric service has the capacity to be a leading ethanol producer in the state. There are 20 proposed facilities in Nebraska and they would add approximately 250 MW new demand to the state's electrical grid. Ethanol plants have the ability to run continuously and thus may have load factors as high as 90%. Estimated annual electrical energy consumption of the 20 proposed plants would be in the range of

would be in the range of 1,970 GWH – nearly 20% of OPPD's current annual generation. Presently there are no new ethanol facilities under consideration in the OPPD service territory. However such large additions of industrial electric power consumers in the region could contribute a noticeable change in the wholesale market as baseload resources are pushed further to meet such growth in retail load.

3.2 Accreditation and Capacity

In 2002, OPPD obtained approvals to construct a 600 MW coal fired unit at the Nebraska City Station (Nebraska City Unit 2). However, as a result of negotiations with vendors, it was determined that a larger 663 MW unit would be more economical. In early-2005, OPPD obtained approvals for the additional 63 MW, thus bringing the total approved capacity to 663 MW. This unit is scheduled for completion in May 2009. A total of 7 participants have purchased a 50% total share of Nebraska City Unit 2 for a total of 331.5 MW. With a planned size of 663 MW, economies of scale have allowed lower construction and operating costs for Unit 2. The regional participants are sharing in this opportunity to purchase this low cost option.

Cass County Station is accredited for 320 MW for the summer season. Cass County Station is designed to burn only natural gas and does not have fuel oil as a supplementary fuel source. With interruptible gas as its only fuel source, Cass County cannot be accredited for the winter season per regional rules. In order to receive winter accreditation, the station would have to add a supplementary oil fuel source, or purchase firm natural gas. Based on the current load forecast, OPPD will have adequate winter reserves for the forecast period, but this situation should be closely monitored for a winter deficit.

As of October 2008 OPPD completed 3 years of purchasing firm wind power from the Ainsworth Wind Energy Facility near Ainsworth, Nebraska in Holt County. According to MAPP accreditation rules, a wind facility must have three years' historical performance to begin using a firm accredited rating of the wind facility in reporting Load and Capability for future months. Therefore, OPPD can now report a firm capacity contribution from Ainsworth of 2.02 MW to contribute towards OPPD's 2009 summer peak load. The 2.02 MW falls in line with an assumption that wind power's accredited capacity is generally in the range of 15 - 20% of the nameplate rating, dependent on the applicable accreditation rules.

OPPD has carried supplemental capacity reserves to meet its MAPP reserve capacity obligation of 15% for many years. OPPD's date of membership to SPP is April 1, 2009. The SPP reserve capacity requirement is 12%. However, in an apples-to-apples equivalency to the MAPP formula, the SPP reserve margin is 13.64%. The SPP formula uses the total capability in the denominator of its calculation. The MAPP formula uses the peak load in the denominator. The 2008 IRP now uses the 13.64% reserve requirement when projecting future resource needs.

Membership in SPP will place OPPD under SPP's facility rating criteria which have differences in generator testing conditions to MAPP's accreditation rules. It is expected this

will change OPPD's thermal and wind generator ratings though the impact should not be significant.

OPPD's Net Generating Capability is listed on Attachment 1.

3.3 Construction Cost Estimates

OPPD uses the Ventyx Midwest Regional Outlook Spring 2008 for resource costs of fossil fueled resources including coal-fueled, integrated gasification combined cycle (IGCC). In early 2008 OPPD received a study from Enercon which detailed costs of building a new nuclear generating unit, a scenario in which OPPD would be a participant. The Enercon study was the basis for the 2008 IRP's nuclear costs. These resources also provide fixed costs and variable costs of operation which are necessary to evaluate total cost of ownership. OPPD has received current costs on wind turbine installations which are the basis of wind power evaluations.

In 2002 and during 2004, OPPD received reports from HDR Engineering that estimated the potential costs to OPPD to meet the potential legislated scenarios for multi-pollutant control standards that could be passed by Congress. This is discussed in Section 5.

Capital cost of most electrical generation technologies have risen considerably. From a cost to build and operate standpoint, coal-fueled generation costs have been especially impacted.

See Attachment 12 to view the installed capital costs for various resources.

4.0 Renewable Energy

This section discusses OPPD's renewable energy policy, provides an overview of OPPD's current renewable energy programs and discusses recent developments related to renewable energy incentives and renewable portfolio standards. Refer to the 2007 IRP for a summary of prior renewable energy studies and reports OPPD has completed.

4.1 OPPD Renewable Energy Policy

OPPD has always valued a diverse fuel mix for generating electricity as a means of promoting reliability and affordability of its product. OPPD recognizes renewables offer an option to maintain or expand its fuel diversity and help address environmental issues and meet customers' desire for sustainable energy. OPPD believes a responsible approach to use of renewable energy resources considers public concerns, environmental issues and good business practices. OPPD will test and monitor renewable energy technology and implement its use based on need and feasibility.

OPPD has conducted research and testing into the use of renewable resources for generating electricity, and has gained first-hand experience through the installation of landfill-gas engines at the Elk City Station, a wind-turbine in Valley, Nebraska, fuel cells at the Henry Doorly Zoo, and a small-scale demonstration project in solar photovoltaic energy. OPPD is also participating in the 59.4 MW NPPD Ainsworth Wind Energy Facility through a 10 MW purchase. The purpose behind such efforts is to help determine how and where renewable resources might best fit into OPPD's generation mix to maximize customer benefit.

OPPD will continue to test small-scale demonstration projects in order to retain updated information for use in accurately evaluating renewable technology options as their costs either decline or increase and their operational performance improves.

4.2 Nebraska Legislation Passage – LB 629, LB 65 and LB 776

LB-629, the Rural Community Based Energy Development Act of 2007, or commonly referred to as C-BED, is having a large impact on wind generation development in Nebraska by being a primary driver for 120 MW of wind by the end of 2009 and possibly another 160 MW of wind to be installed before 2012. C-BED projects are privately financed and require a minimum of one-third of the power purchase payments flowing to owners with in-state interests or to local communities. These projects can be up to 80 MW in size and not require Nebraska Power Review Board approval. Instead, renewable projects under 80 MW can qualify under federal PURPA guidelines which supersede Power Review Board statutory authority. Projects do need a buyer for the delivered energy (including transmission costs) so the energy must be competitively priced. Since C-BED wind energy facilities are being funded wholly or partially by private sector monies, the energy produced by these facilities will be eligible for renewable Production Tax Credits – currently wind energy facilities must be commissioned by December 31, 2009 to be eligible (see PTC

discussion under Section 4.7).

Passage of LB 65, a bill supported by OPPD, by the 2003 Legislature allows a Nebraska utility to build and generate up to 10 MW of renewable and emerging technology generation facilities without meeting the least-cost option criteria. Applications for such projects must, however, show some public benefit and receive approval from the Nebraska Power Review Board. The passage of C-BED along with the strong economics of wind generation has reduced the usefulness of LB 65 as it applies to wind projects. However, the law retains its usefulness for other less affordable renewable technologies.

LB 776 passed in the Nebraska Legislature in 2006. This legislation allows yard waste disposal in landfills for methane recovery. This might enable future capacity expansion opportunities at Elk City Station.

4.3 Current OPPD Renewable Energy Projects

In recent years OPPD has completed several new and innovative renewable energy projects such as a 660 kW wind turbine, and a 6,000 kW landfill gas-to-energy facility. OPPD is purchasing 10,000 kW from the NPPD Ainsworth Wind Energy Facility. OPPD has several other testing and monitoring projects for fuel cells, microturbines and photovoltaic generation. OPPD also offers its customer-owners a green power rate.

Request for Proposals – 80 MW Wind Energy

OPPD intends to enter a purchase power agreement with a wind developer and operator for 80 MW of wind energy. Selection of a successful bidder is to be accomplished by 2nd quarter 2009.

NPPD Solicited C-BED Projects

NPPD is entering agreements for up to 120 MW of wind energy in the Bloomfield, Nebraska area in Knox County. OPPD has intentions to enter purchase power agreements with NPPD for as much as 38 MW.

Valmont Prototype Wind Turbine

OPPD's first renewable energy project was the installation of a 660 kW Vestas Wind Turbine in a joint project with Valmont Industries. This turbine was put into commercial service on December 21, 2001 at a site near Valley, Nebraska. Initially, it involved a prototype tower and lift system designed by Valmont with the goal of making utility wind projects more economical by reducing construction and maintenance costs. The prototype tower was replaced with a new structure and returned to operation in June 2003. Monthly capacity factors have ranged from a low of 6.3% in July 2004 to a high of 33.7% in March 2004.

Elk City Landfill Gas Facility

OPPD owns a landfill gas-to-energy facility located at the Douglas County Landfill near Elk City, Nebraska. This facility is operated by Waste Management, Inc. Methane gas produced by decomposing garbage is captured and used as fuel to power seven nominal 800-kilowatt internal combustion engine/generator sets. Eight units are currently installed at the station, but there is currently enough gas available for seven units. The facility is currently accredited for 5.32 MW. It is expected that there will be enough landfill gas available by 2009 to operate the eighth unit. Using renewable landfill gas reduces the consumption of other fossil fuels and converts what would normally be a waste product into useful fuel. Elk City Station has operated at near 100% capacity factor since it was placed in-service in 2002. In 2008 it generated at a capacity factor of 99.0%. It is the only plant of its type in Nebraska.

Landfills represent the largest source of methane emissions in the United States and methane is second to carbon dioxide as a major contributor to potential greenhouse warming. Over long periods of time, methane is estimated to be 21 times more potent than carbon dioxide as a greenhouse gas.

Elk City Station energy production failed to qualify for any REPI dollars (refer to Section 4.7) for fiscal year ending 2003 and 2004. During those years landfill gas was classified as a Tier 2 renewable project and no landfill gas facilities in the U.S. received REPI dollars (see Section 4.8 for further details). OPPD has received REPI funds for Elk City Station energy during fiscal years 2005, 2006 and 2007.

NPPD Ainsworth Wind Energy Facility

OPPD has a significant commitment to renewable energy through the purchase of a 10 MW (16.8%) share of the 59.4 MW NPPD wind energy facility near Ainsworth, Nebraska. This facility began commercial operation on September 15, 2005. The project costs provided by NPPD show the cost of energy to OPPD will be 3.4 cents/kWh – levelized over 30 years assuming no REPI payments. During the first year of operation, October 2005 through September 2006, the Ainsworth Wind Energy Facility generated at a 43.6% capacity factor. During the second year of operation, October 2006 through September 2007, Ainsworth generated at a 37.5% Capacity Factor. During the third year of operation, October 2007 through September 2008, Ainsworth generated at a 33.2% Capacity Factor.

Fuel Cells and Distributed Generation

OPPD has been testing a 200 kW commercial-size fuel cell since 2001, located at Omaha's Henry Doorly Zoo and was sized to meet 50% of the Lied Jungle's electrical requirements. In the 3rd quarter 2008, the zoo fuel cell was decommissioned due to declining reliability and expense to repair. OPPD has a 60 kW micro-turbine distributed generation research project and a photovoltaic cell installation at the Blair Office and Elkhorn Center respectively. These projects are part of ongoing research into distributed generation technologies.

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

4.4 Renewable Energy Rate

Renewable power programs promote the use of renewable electric generation by providing a mechanism for electric customers to financially support the use of resources such as wind, solar, or biomass. Some customers in Nebraska have voluntarily enrolled in such programs and pay a premium for renewable energy.

OPPD began offering a renewable energy rate on January 1, 2002. Customers interested in purchasing power from the OPPD renewable energy facilities can do so at a slightly higher "green" rate. Residential customers can participate at four levels, ranging from $4.50 per month to $30.00 per month. Commercial customers can purchase varying percentages of their load as renewable power at an additional cost of 3 cents per kWh.

In addition to the installation costs for renewable technology, renewable energy programs typically require additional expenditures for advertising and promotion. Most programs take several years of consistent promotion to develop their full potential.

4.5 Policy Actions Necessary, Renewable Generation

The Nebraska electric utility industry has communicated four key areas where further action is needed to advance the use of renewable forms of generation on Nebraska's electric system.

1. Incentives Needed – Public power utilities must have federal and state financial incentives for renewable energy development comparable to those available to investor-owned utilities. Incentives should be stable and long-term.
2. Statutory Changes – Accommodation for significant additional renewable resources may require statutory changes to focus on issues other than least cost or otherwise give priority, where practical, to energy efficiency and renewable generation resources. Statutory changes may also be needed in the case where significant transmissions additions are needed to export renewable energy to load centers outside the state.
3. Studies Needed – For significant renewable resource additions such as wind, more information on cost impacts and integration are needed.
4. Public Education – Nebraska utilities, policy makers and other entities have a critical educational role to play to lead the public through the coming transition period to a future with new regulatory requirements.

4.6 Nebraska Wind Studies

Section 4 of the 2007 IRP provides summaries of some renewable related studies OPPD has undertaken before 2006 which are not repeated here.

Beginning in October, 2008 a state-wide Nebraska Wind Integration Study is being performed. This study will take 11 months to complete. Funding is provided by the National Renewable Energy Laboratory (NREL) and a combination of matching funds from the Nebraska Power Association (NPA) and through matching in-kind work performed by the Nebraska utilities involved in the study, including OPPD. The consulting firms of Ventyx and Enernex have been retained to contribute regional nodal market analysis and intra hour system statistical studies. A key finding will be the cost borne by the rest of Nebraska's power system to make up for wind generation's characteristics of variability and uncertainty under various wind penetrations, including a case with 20% contribution of wind energy towards the state's total electrical energy requirements.

The NPA issued a reference document titled, Renewable Energy Background and Outlook for Nebraska Electricity Consumers. The document was published on December 28, 2007. This document was produced to describe potential impacts to the Nebraska electrical system and the state's electrical consumers given a future scenario of RPS or climate change legislation.

4.7 Renewable Energy Production Incentive

The federally funded Renewable Energy Production Incentive (REPI) is available to public entities such as OPPD to encourage investment in renewable energy projects. After expiring in 2003, the REPI program was reauthorized and extended by 10 years with the passage of the 2005 Energy Policy Act by Congress.

Congress established REPI to provide public utilities with benefits commensurate with those available to investor-owned utilities through their use of the renewable production tax credit (PTC). Created by the Energy Policy Act of 1992, REPI authorizes the Department of Energy to make payments of 1.5 cents/kWh (1993 dollars indexed for inflation) for energy produced from eligible renewable energy sources (e.g., solar, wind, geothermal, closed-loop biomass, landfill gas-to-energy).

REPI Appropriations and Payments

Unlike the tax credits awarded to investor-owned utilities and other renewable investors, the REPI program is inherently uncertain because payments are dependent on the availability of annual appropriations. If there are insufficient appropriations to make full payments for energy produced from all qualifying facilities, then there is a process for partial payment calculations based on the prior year's energy production. A major change made by the Energy Policy Act of 2005 is that when applications exceed appropriations, 60% of available funds will go to wind, solar, and ocean energy projects and 40% to other eligible projects.

Table 4 - REPI Appropriation Summary

Year of Production (FY)	Year of Payment (FY)	Appropriated Funds	Tier 1 Paid	Tier 1 Unpaid	Tier 2 Paid
1994	1995	$3,000,000	$100,725	-	$592,395
1995	1996	$2,988,000	$218,604	-	$2,178,217
1996	1997	$2,490,894	$195,902	-	$2,294,992
1997	1998	$2,853,997	$154,504	-	$2,699,493
1998	1999	$4,000,000	$122,167	-	$3,877,833
1999	2000	$1,500,000	$603,179	-	$896,821
2000	2001	$3,991,000	$1,339,377	-	$2,651,623
2001	2002	$3,787,000	$1,365,846	-	$2,421,154
2002	2003	$4,815,033	$1,810,911	-	$3,004,122
2003	2004	$3,714,920	$3,714,920	$1,091,206	$0
2004	2005	$4,960,000	$4,960,000	$2,205,009	$0
2005	2006	$4,925,375	$2,955,255	$6,323,364	$1,970,150
2006	2007	$4,900,000	$2,940,000	$8,149,897	$1,960,000
2007	2008	$4,500,000	$2,700,000	$11.25 M	$1,800,000

Tier 1 qualifying facilities are facilities that use solar, wind, geothermal, or closed-loop (dedicated energy crops) biomass technologies to generate electricity. Tier 2 facilities consist of open-loop biomass technologies, such as biomass digester gas and plant waste material. Due to the REPI statute revisions of the 2005 Energy Policy Act, landfill gas facilities are re-classified as Tier 1 facilities. If there are insufficient funds to make full payments to all Tier 2 qualifying facilities, payments are split 60% to Tier 1 and 40% to Tier 2.

Before fiscal year ending 2003 (the 12 months prior to September 30, 2003) 100% full payments had been made for energy produced by Tier 1 facilities and partial payments on a pro rata basis had been made to Tier 2 facilities. Tier 2 REPI applicants for energy generated during fiscal years ending 2003 and 2004 received no incentives. Before the 2005 Energy Policy Act, the OPPD Elk City Station received no REPI funds. However, now that landfill gas has been reclassified as a Tier 1 facility Elk City received $133,000 in REPI funds for FY 2005 and FY 2006 generation; and $183,765 funds for FY 2007 generation or

0.4 cents/kWh. OPPD has applied for REPI funds for Elk City generation during FY 2008. Annual REPI appropriations and payments on a U.S. wide basis are shown in Table 4.

Status of Renewable Energy Production Incentive - REPI

The REPI program has been under-funded, and it does not guarantee incentive payments over a ten-year period. These uncertainties must be considered in economic analysis and integrated resource planning. The base case of the 2008 IRP does not include the 1.9 cent/kWh REPI (1993 dollars indexed for inflation). Inflating and levelizing the REPI over 30 years, the REPI incentive, if fully funded, is approximately 1 cent/kWh. The on-going uncertainty and chronic under-funding in the REPI program will prevent OPPD from taking the risk of relying on REPI payments when financing and building future renewable energy generation facilities. For example, for several years the Elk City Station did not receive any REPI payments due to the limited appropriations and during 2001-2003 it was classified as a Tier 2 facility. Regardless of incentive availability, OPPD is continually evaluating the economic feasibility of renewable energy resources, and currently owns or is a participant in several renewable energy programs.

After expiring in 2003, the REPI program was reauthorized and extended by 10 years with the passage of the 2005 Energy Policy Act. Subject to the availability of appropriated funds, incentive payments are made for ten fiscal years. Payments under the reauthorized program end September 30, 2026 for facilities placed in-service by October 1, 2016. The REPI allocation for FY 2007 is $4.5 million, $400,000 less than appropriated in FY 2006.

Status of Production Tax Credits - PTC

Tax paying utilities (investor-owned and privately held) and tax paying developers receive a production tax credit for eligible renewable energy production. The PTC's advantage over REPI is that it is not dependent on appropriations. The project financier will get the full value of the tax credit as long as their federal tax burden is large enough to be offset with the PTC. The PTC has had a history of uncertainty as observed by Congress' lack of timeliness in extending the provision.

In October 2008, the Emergency Economic Stabilization Act was passed into law and extended the PTC credit for wind energy through December 31, 2009. The PTC is currently worth 2.0 cents/kWh and is provided for the first 10 years of operation.

Congress let the production tax credit expire on December 31, 2003. As a result many new renewable energy projects in 2004 were put on the back-burner. However, in October 2004 as part of a tax package, the PTC was re-enacted into law through 2005, and retroactively to the beginning of 2004. The 2005 Energy Policy Act extended the PTC through December of 2007. This was the first time that an extension of the PTC had been approved before the credit expired. In late-2006, Congress passed legislation which once again extended the PTC. It was extended through December 31, 2008.

4.8 Clean Renewable Energy Bonds (CREBs)

The recently enacted Energy Policy Act of 2005 includes a provision granting State and local governments and cooperatives the ability to issue clean renewable energy bonds ("CREBs"). CREBs are a tax credit bond that are designed to provide the borrower with an interest free loan and the holder of the bonds with a tax credit (rather than interest) in an amount intended to provide an after tax return equal to that of a comparable taxable investment. The issuer must spend 95% or more of the proceeds of the bond on a qualified project within five years from the date of issue.

In November 2006 the IRS announced allocation of $800 million in CREBs for a total of 610 renewable projects from across the country. The funds were allocated from smallest projects to largest until the funds were exhausted. OPPD applied for CREB's for the Elk City Station expansion, but the project was not chosen for this incentive. Nominated projects from governmental entities including public power districts received funds if they were under $3.2 million. The Elk City project cost was estimated at $4 million.

CREBs result in a subsidy that is approximately the same as the REPI incentive payment. Recent OPPD analysis shows that if the NPPD Ainsworth Wind Energy facility were built with no interest financing then the 20-year levelized busbar cost would be approximately 1 cent/kWh less then the current estimated cost (without REPI). The current REPI incentive is 1.9 cent/kWh (indexed for inflation) over a 10-year period. Inflating and levelizing the REPI over 20 years, the REPI incentive is approximately 1 cent/kWh, if fully funded.

4.9 Renewable Energy Portfolio Standard

In recent years, both a federal and Nebraska-based renewable portfolio standard has been introduced in both the U.S. Senate and in the Nebraska Unicameral. Neither action was passed into law, but reintroduction of RPS requirements remains a possibility. A minimum of 26 states have enacted RPS legislation of varying percentage requirements and time deadlines. The growing number of states implementing an RPS may reduce the possibility of a federal plan. Given the varying geography and renewable potential across the 50 states, state implementation of standards may be more sensible.

Potential Impact of RPS Mandate on OPPD

If a 10% standard were passed into law, OPPD would most likely rely primarily on wind energy capacity to meet the standard. At a capacity of 6,000 kW, Elk City would only contribute 3% of the amount of renewable energy required in 2016. At a capacity factor of 24%, a total of 600 MW of wind energy nameplate would be required to meet the requirements. At a capacity factor of 36%, 400 MW of wind energy capacity would be required to meet the requirement. A wind facility with a capacity factor of 36% or greater would most likely be located outside of the OPPD service territory (in out-state Nebraska). This would most likely be more economical than a facility located within the OPPD service territory, depending on each location's transmission costs. The most recent cost estimates show that the capital cost for large-scale wind facility installations is approximately

$2,100/kW for the production facility without transmission upgrade costs. Therefore, the capital expenditure to meet a 10% RPS could be over $800 million for a 400 MW out-state wind energy facility.

Although efforts to pass an RPS in Nebraska and nationwide have been unsuccessful to date, it remains a possibility.

5.0 Environmental Considerations

The 2008 IRP considers and selects resource options to meet the forecasted demand, at an acceptable level of reliability, ensuring environmental preservation. Among the largest uncertainties when planning for future generation is change in environmental regulations. Given the political nature of these types of regulations, predictions are difficult. Current as well as future environmental regulations will have a significant impact on the operation and selection of future power supply resources. OPPD will consider all resource alternatives available to develop a least-cost compliance plan

Important environmental considerations of the Clean Air Act Amendments, potential Multi-Pollutant Control (MPC) legislation and potential carbon legislation are discussed in this section.

5.1 1990 Clean Air Act Amendments

The environmental impacts associated with fossil-fuel fired generating units have received considerable world-wide attention. In response to environmental concerns, Congress passed the 1990 Clean Air Act Amendments (CAAA). The CAAA are the source of many existing regulations that limit emissions from coal-fired plants. Listed are some key amendments included in the CAAA that impact electrical generators:

1. Acid Rain Program – Acid Deposition Control
2. NO_X State Implementation Plan
3. New Source Review
4. Clean Air Interstate Rule (CAIR) – March 2005 - Currently Vacated
5. Clean Air Mercury Rule (CAMR) – March 2005 – Currently Vacated
6. Final Amendments to Regional Haze Rule (RHR) – June 2005
7. National Ambient Air Quality Standards – Revisions announced September 2006 for Particulates (PM); Ozone proposed rule expected in 2007

The Environmental Protection Agency is authorized to enforce the amendments. The CAAA provide multiple regulations for the same pollutant since that pollutant may have an affect on more than one of the amendments above. The latest regulations issued by the EPA were the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule issued in March 2005; the Regional Haze Rule (RHR) issued in June 2005; and revisions to the National Ambient Air Quality Standards (NAAQS) announced September 2006. Nebraska was not included in CAIR since it does not adversely affect cities with NAAQS compliance problems. Regardless, the certainty of CAIR is unknown due to a court ruling in 2nd quarter 2008 effectively vacating CAIR. The Clean Air Mercury Rule (CAMR) has also been vacated in court action. OPPD will have to make modifications at Nebraska City Unit 1 due to the RHR. Air quality in the OPPD service area currently meets the new, tighter daily standard on fine particles of NAAQS. This rule change will go into effect in 2015. Section 5.8 of the IRP discusses the New Source Performance Standards. Other impacts of the CAAA are referenced at different points within the text of this section. A Supreme Court ruling in 2007 stated the EPA has the authority to regulate carbon dioxide

(greenhouse gas) emissions. The full ramifications of this decision are still evolving to the extent it may impact electric utility emissions from fossil fuel plants.

5.2 Cap and Trade Programs

In a cap and trade program, utility generation units are allocated allowances based on a desired regional or nation-wide goal of emission reductions. It is possible that allowances under a CO_2 program would be auctioned or sold instead of being allocated. The quantity of allowances granted per year places the cap on the amount of emissions. An allowance is equal to a measurable quantity of emissions, for example, one ton of SO_2.

With cap and trade, utilities meet their emission requirements in the most cost effective manner: either by utilizing the station less or burning a different fuel variety; adding emission controls or buying necessary allowances on the cap and trade market to balance emissions in excess of allowances. Utilities whose actual emissions are less than their allowances become sellers in the allowance market.

The EPA has declared the SO_2 cap and trade program under the Acid Rain Program a success. A cap and trade program is used in the 22 state NO_X SIP call plan. When CO_2 mandatory reductions are passed into law, the law will likely utilize a cap and trade program.

Table 5 provides a summary of the active and potential cap and trade programs for sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury (Hg) and carbon dioxide (CO_2). Refer to the sub-sections that follow for each emission for more details. The first 4 rows of Table 5 address those programs that actively pertain to OPPD. Regional, state, and local CO_2 programs are in effect but no national program exists. Rows 5 and 6 denote other active or pending programs in the U.S. The second to the last row denotes the range of targets (caps) OPPD would be required to meet under passage of MPC legislation. The last row denotes actual or expected trading ranges for the emission allowances. The emissions targeted by these programs are produced from coal combustion (coal contains sulfur and mercury) and to a lesser extent oil and natural gas combustion. NO_X and CO_2 are produced by the combustion of any hydrocarbon or bio-material.

Table 5 – Summary of Cap and Trade Emission Programs

Emission	SO_2	NO_X	Hg	CO_2	CO_2 (Voluntary)
Program	Acid Rain Program	Acid Rain Program	Vacated Clean Air Mercury Rule (CAMR)	* None	Power Partners (APPA, LPPC)
OPPD Status	Ph 2 - 2000	Ph 2 - 2000, Early Compliance - 2008	EPA will define Max Achievable Control Tech	Supreme Court ruled EPA can regulate	MOU Signed
Annual Allowances or Emission Rate (NO_X) Limits	2005 – 09: 30,573 tons, 2010 and beyond: 23,334 tons	NO5, NC1: 0.46 lb/MMBtu; NO 1-4: 0.40 lb/MMBtu 2008	No current limits due to Vacature of CAMR	Most proposals set a multi-year reduction schedule	3 – 5% intensity reduction 2010-12 /2000-02
Note on Programs	OPPD Deficit concerns – 2011 – 14	Acid Rain NO_X is not cap and trade program. OPPD units currently below	EPA requesting Supreme Court review	*	Utility-wide intensity decrease
Program: Clean Air Interstate Rule (CAIR)	Vacated by Court Order in 2008	Vacated by Court Order in 2008			
Other Regional Programs in U.S.		Eastern U.S. NO_X SIP Call 22 States, Houston/ Galveston	Uncertain if some states may proceed with restrictions on Hg	RGGI – N.E. U.S. 2009; GWSA – Calif., 1990 levels by 2020	Individual Utility Goals, State/City Programs
Expected Targets of Multi-Pollutant Control	~ 75% further decrease to Acid Rain	~ 70% decrease to current OPPD emissions	Maximum Achievable Control Technology	If included in MPC, may fall in range of Lieb-War	
Approx. Current Trading Market	2009 $90/Ton 2010-39 $87/Ton	NO_X SIP Market: $500/ton	$5,000 – 10,000/lb (estimate - no market)	European Union: $13/ton	

5.3 Emission Compliance Costs

The costs associated with the effluent models in the 2008 IRP are shown in Attachment 8. These costs are used to estimate future emission compliance costs, and thus become a significant cost associated with coal-fired units when developing the OPPD 15 Year Plan.

Based on the work by the multi-pollutant controls task force, the allowance prices for environmental externality costs will be revised for future effluent models. These effluent models are developed in Strategist and have a significant impact on the OPPD 15 Year Plan.

Regulatory changes have the potential to significantly increase future emission compliance costs. Technological advances could also increase or decrease future emission compliance costs. OPPD will continue to monitor future developments and develop a least-cost compliance plan.

5.4 SO_2 Allowances

OPPD continues as a participant in the SO_2 Acid Rain cap and trade program under EPA's Phase 2 implementation in January 1, 2000. In this program surplus allowances in one year can be carried forward to future years. In 2010 permanent allowances begin ("bonus" allowances end).

At current and expected emission rates at North Omaha and Nebraska City Station, ignoring other potential regulatory mandate scenarios, OPPD will go deficit in SO_2 allowances, potentially as early as 2010 or 2011 as shown in Attachment 9. The 2010 deficit is based on a SO_2 emission rate of 0.8 lb/MMBtu for North Omaha Units and Nebraska City Unit 1 for 2009 and beyond. 2009 is the start of OPPD's new 5 year coal purchase contract. Actual emission rates may vary as coal spot purchases contribute to OPPD's overall coal consumption.

Attachment 9 also shows a Low SO_2 Cumulative Allowances line which delays OPPD's deficit year to 2015 – 16. This line is based on a SO_2 emission rate of 0.7 lb/MMBtu (instead of 0.8 lb/MMBtu) for North Omaha Units and Nebraska City Unit 1, 2009 and beyond. A look at OPPD's actual SO_2 emissions for years 2000 – 2007, shows annual system-wide SO_2 emission rates under 0.7 lb/MMBtu for 5 out of 8 years and rates under 0.8 lb/MMBtu for all 8 years. If actual historical SO_2 emissions are an indicator, then OPPD's year of deficit potentially could be delayed to 2012 or 2013 time frame.

This upcoming deficit will require careful analysis of ongoing plant performance, purchased coal sulfur content and tracking the SO_2 cap and trade market as OPPD may have to purchase significant SO_2 allowances.

The Clean Air Interstate Rule (CAIR) finalized in March 2005 was to reduce SO_2 further. CAIR was vacated by court action in the 2nd quarter of 2008. See the 2007 IRP for

background on how CAIR was to be structured.

In the 2008 IRP base case, SO_2 effluents are priced at $90/ton in 2009 which reflected the open market trading price of allowances at the time of analysis. A scenario which could drive the prices of SO_2 allowances up would be passage of a multi-pollutant control standard. This would lower the allocated allowances for emission sources to a greater degree than the Acid Rain Program and increase demand for allowances in the market.

5.5 NO_x Emissions

NO_X emission contributes to acid rain and is a source of ground level ozone which is a contributing factor to smog. Under the EPA Acid Rain Program OPPD is required to meet certain NO_X emission rates at its coal fired stations. Modifications were required at OPPD stations. The North Omaha units and Nebraska City Unit 1 meet the Acid Rain Program. Currently, the Acid Rain Program does not include a nation-wide cap on emissions for NO_x nor provisions for a NO_x trading program. The new source review performance standards also established performance guidelines for NO_X emissions which are based on 3-hour contiguous performance.

Under the Acid Rain program, NO_X emission requirements for coal-fired power plants were established. Beginning in 2008 lower annual average NO_X emissions will be required at North Omaha Unit 4 and Nebraska City Unit 1 coal-fired units. These units were elected for early compliance, and current emission levels for these units are lower than the 2008 requirements.

The evolution of NO_X cap and trade programs on a regional basis are discussed in the 2003 and 2004 IRPs. Currently 22 states east of the Mississippi River, participate in EPA State Implementation Plan (SIP). These states all contain counties which have regional haze and ozone air quality problems, called non-attainment areas.

The Clean Air Interstate Rule intent was to reduce NO_X emissions in twenty-eight eastern states. As mentioned above CAIR was vacated by court decision in the 2nd quarter of 2008.

The EPA standard on ozone will potentially be modified by as soon as 2008. The existing standard is 0.08 parts per million (ppm) for ozone and is currently met by all counties in Nebraska and Iowa. If the EPA decides to lower the ozone standard to 0.07 ppm, several counties in the OPPD service area would become non-attainment counties under the NAAQS.

Attachment 10 compares OPPD's projected NO_x emissions based on current emission rates of 0.313 lb/MMBtu for North Omaha Units 1-3, 0.331 lb/MMBtu for North Omaha Unit 4, 0.298 lb/MMBtu for North Omaha Unit 5, 0.394 lb/MMBtu for Nebraska City Unit 1, and 0.07 lb/MMBtu for Nebraska City Unit 2. It is expected that future MPC controls could reduce NO_x emissions by approximately 70% for the existing units. The projected

allowances in Attachment 10 are based on HDR's analysis of the emission limits required to comply with proposed MPC legislation. It will be very difficult to meet the projected allowances without installing SCRs to control NO_X emissions from OPPD's coal-fired units.

As reported in the analysis by HDR, the MPC legislative proposals currently considered feasible all contain more stringent NO_X guidelines than OPPD can currently meet. As with SO_2 emissions, the MPC task force is analyzing OPPD's course of action to meet more stringent NO_X emission requirements if enacted. OPPD would likely be required to install low NO_x burners and SCR's to control NO_x emissions from coal-fired units, and possibly on natural gas-fired combined cycle units as well (OPPD does not have any combined cycle units at the present time).

5.6 Mercury Compliance

In March 2005 the EPA issued its final Clean Air Mercury Rule (CAMR) for controlling mercury emissions from electric utility steam generating units. The EPA concluded that steam electric utility generating units did not fit the definition of a major source of mercury emissions and, therefore, not subject to maximum achievable control technologies (MACT) requirements. CAMR proposed a mercury cap-and-trade program for existing coal-fired power plants, placed limits on new sources and established two nationwide mercury caps – 38 tons in 2010 (Phase I) and 15 tons in 2018 (Phase II). On February 8, 2008, the U.S. Court of Appeals for the Second Circuit vacated CAMR. In the Court's opinion, EPA could not remove mercury as a hazardous air pollutant and substitute a cap-and-trade program without strict adherence to requirements of the Clean Air Act. Thus, steam electric generating units will once again likely be subject to MACT standards. This will require EPA to evaluate appropriate MACT limits for source categories and propose a new regulatory program for mercury control. In September 2008 the EPA asked the US Supreme Court to review of the Second Circuit Court vacature of CAMR. As a result of such uncertainties, neither costs nor time frames can be established at this time.

5.7 Particulates Air Pollutant Costs

The particulate externality pricing is based on the cost to install and operate electrostatic precipitators and/or high efficient baghouses to control particulate matter. On September 21, 2006 the EPA announced new requirements for particulate matter of 2.5 µm in diameter and smaller ($PM_{2.5}$). For the 24-hour standard, the existing 65 $\mu g/m^3$ will be lowered in 2015 to 35 $\mu g/m^3$. The annual standard for $PM_{2.5}$ of 15 $\mu g/m^3$ will remain unchanged. Concerning course particulate matter, defined as ranging in size from 2.5 to 10 µm in diameter (PM_{10}), the EPA revoked the 50 $\mu g/m^3$ annual standard and leaves the 24 hour standard unchanged at 150 $\mu g/m^3$. According to the Nebraska Department of Environmental Quality's ambient air monitoring data, Nebraska currently meets the more stringent fine particulate matter ($PM_{2.5}$) standards, which will become effective in 2015. Coarse particulate matter (PM_{10}) is not currently monitored in Nebraska.

5.8 New Source Performance Standards

The 1990 CAAA contained a section entitled "Standards of Performance of New Stationary Sources". These standards are intended to promote use of the best air pollution control technologies - taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources which have been constructed or modified since the proposal of the standard. Generally, state and local air pollution control agencies are responsible for implementation, compliance assistance, and enforcement of the New Source Performance Standards (NSPS).

These standards would apply to all new units. In order to meet NSPS, all new coal-fired units are expected to require baghouses, scrubbers, and selective catalytic reduction (SCR). Cost estimates used in developing the OPPD 15 Year Plan reflect these environmental controls.

5.9 Multi-Pollutant Controls (MPC) Considerations

While OPPD coal-fired units currently meet or exceed the existing applicable regulatory requirements related to emissions, there are certain federal legislative changes pending that would further restrict emissions requirements. These pending changes exist as legislative proposals and are generally referred to as Multi-Pollutant Control (MPC) proposals. Several competing proposals would be as restrictive on the above emissions and possibly add CO_2 reduction goals as well.

Given the political nature of these types of regulations however, any prediction of MPC passage is hardly certain. Regardless of the form of initiative, it seems apparent that all coal-fired power plants in the U.S. will need to have MPC equipment installed at some point in the future. In the meantime OPPD must continue to meet regulatory requirements as set under the Clean Air Act Amendments (CAAA). The Regional Haze Rule (effective in 2014 - 2018) will likely impact Nebraska's two largest coal-fueled generating stations and will require reductions in their emissions. Due to these expanding rules, a large portion of the nation's coal fleet will be retrofitted with pollution control equipment in the next 5 to 10 years even without enactment of MPC legislation. Congress may be satisfied with this progress; however, there is an observed diminished enforcement under New Source Review due to interpretations in the courts. Also with the court ordered vacature of the Clean Air Interstate Rule and Clean Air Mercury Rule, Congress may feel there is need for MPC legislation. Recently, congressional environmental related initiatives are focusing on CO_2 and greenhouse gas emissions.

A study by HDR, "Multi-Pollutant Control Capital and O&M Expenditures Planning Analysis", was completed for OPPD in the summer of 2002 and updated in January of 2005. HDR assumes MPC legislation will require selective catalytic reduction (SCR) for NO_x control, a spray dryer absorber (scrubber) for flue gas desulfurization SO_2 control, activated carbon injection for mercury control and a baghouse for particulate control at North Omaha and Nebraska City Unit 1. The HDR study also estimates allowable emission

rates that must be achieved from each of the units. With the addition of these pollution controls, OPPD would meet the Regional Haze Rule.

The continual evolution of pollution regulations will be shaped by EPA CAAA rule revisions and issuances, precedent setting rulings in the courts and the attitudes of Congress towards MPC legislation. The scope and timing assumptions for multi-pollutant controls are subject to change by the next IRP. However, the assumed allowances in the Strategist model are based on the enactment of MPC legislation as of 2012 requiring the full array of controls. OPPD's stations are not modeled to have the full array of available controls by that time. Since the Strategist simulation will purchase deficit allowances, a larger cost, or financial penalty, is placed on plant emissions in the 2008 IRP. A sensitivity analysis within the Strategist model based on varying allowance costs is presented in Section 9.2.

5.10 Carbon Dioxide Emission Costs

Attachment 11 shows OPPD's historical CO_2 emissions for the period 1987 through 2007. Currently the monetization of externalities as they relate to carbon monoxide (CO) and carbon dioxide (CO_2) are highly speculative. However, throughout the electric utility industry, it is widely believed that it is unlikely that greenhouse gas emissions will continue to cost electric utilities nothing what-so-ever over the long lifetime of newly constructed units. Given the uncertainties and current status of greenhouse gas studies and related legislation, it is very difficult to quantitatively assign an externality pricing to these emissions. Thus, this cost is considered in the evaluation of resource options and selecting the OPPD 15 Year Plan.

The 2008 IRP assumes a carbon tax of $5/ton beginning in 2012 and increases annually by $0, $1 and $2 increments until a $23/ton tax is reached in 2032. This tax is placed on CO_2 emissions above and beyond predefined allowances. In addition to the base value, the 2008 IRP also considered sensitivity cases including a very high case with a peak of $46/ton and a no carbon tax case. OPPD will continue to closely monitor any developments related to future carbon emission costs, taxes, or related legislation.

Greenhouse Gas Intensity

In 2002, President Bush announced his Climate VISION program. This program established a goal of reducing the greenhouse gas intensity of the U.S. economy (measured as equivalent emissions per unit of economic output) by 18% by 2012. For electric power production, this intensity is measured as tons of CO_2 per MWh.

The Electric Power Industry Climate Initiative (EPICI) was formed by representatives of the electric utility industry to work in partnership with the federal government. The purpose of the initiative is to help meet President Bush's voluntary GHG emission intensity reduction goal. Members of EPICI, known as "Power Partners", include among others, the Large Public Power Council (LPPC) and the American Public Power Association (APPA). OPPD participates in Power Partners through its memberships in both LPPC and APPA.

In December 2004, the U.S. Department of Energy (DOE) and Power Partners signed a Memorandum of Understanding (MOU) establishing a voluntary framework for reducing greenhouse gas intensity of the power generation sector. Power Partners have pledged to reduce collectively the power sectors' GHG emissions intensity by an equivalent of 3 – 5% below 2000-2002 baseline levels, as measured over the 2010 to 2012 period. (It is important to note that the MOU and its pledged reduction do not apply individually to OPPD or any utility. This goal applies to the entire electric power sector.)

OPPD's GHG intensity will raise over time because overall generation increases and nuclear generation becomes a lower percentage of total generation.

Climate Stewardship Act (McCain-Lieberman)

In Section 10.8 of the 2004 IRP an analysis of impacts of the Climate Stewardship Act sponsored by Senators John McCain and Joe Lieberman is detailed. This proposal has since been superseded by more recent climate change related proposals. Passage of some form of the bill remains likely given a potential growing base of those that support mandatory greenhouse gas reductions. The Climate Stewardship Act included a mandatory cap under which CO_2 emissions would be reduced to 2000 levels by 2010; then further reduced to 1990 levels by 2016. This equates to a 14% reduction in CO_2 from current practices by 2010 and a 40% decrease by 2016.

The impact analysis derived a cost for OPPD to meet McCain-Lieberman by fuel switching some portion of North Omaha Station and Nebraska City Station fuel usage from coal to natural gas. To meet 2010 McCain-Lieberman goals approximately 60% of North Omaha's fuel energy would be from natural gas. To meet 2016 goals 100% of North Omaha Station and 10% of Nebraska City Station fuel energy would need to come from natural gas.

The cost of this fuel switching varies with the volatility in natural gas prices. In the 2004 IRP, at a time when natural gas was approximately 5-times the price of coal per unit of energy content (e.g. in $/Btu), this fuel switching cost was in the vicinity of $110 million per year to meet the 2010 goal and $275 million per year to meet the 2016 goal. Long term forecasts for natural gas and coal, place natural gas energy at 5 times the cost of coal.

The cost of natural gas that was used in this high level analysis, did not attempt to predict the impact of this legislation on future natural gas prices or availability. In reality, this country may not have enough natural gas or transportation pipeline capacity for the entire electric industry to achieve compliance using the fuel-switch option. The above costs represent only the financial impact of the fuel switch compliance option. OPPD has also performed additional analysis for other options, such as wind, wind with combustion turbine backup, and advanced nuclear. However, a detailed and comprehensive analysis of all available compliance options is necessary in order to fully evaluate the least-cost option.

This high level analysis points out the significant financial impact of mandatory CO_2 reductions on the District. Furthermore, in the event of CO_2 caps, it is quite possible that different resources would be required to meet the District's forecasted load growth. It could

be necessary to convert or replace existing generation units with natural gas combined-cycle units or necessary to construct natural gas combined-cycle units rather than baseload coal units. OPPD will continue to monitor carbon legislation and assess the impact that any future legislation could have on operations and the District's future power supply plan.

5.11 Missouri River – U.S. Army Corps of Engineers Master Manual

Missouri River issues are discussed in the 2004, 2005 and 2006 IRPs. Please refer to these IRP for pertinent discussion on key Missouri River Issues.

6.0 Supply-side Options

This section discusses the supply-side option screening, power uprates from various projects at Ft. Calhoun, the supply-side options that are being considered for the next baseload unit, and the current assumptions regarding the wind energy option.

6.1 Supply-Side Option Screening

The 2008 IRP considered supply-side resource technologies expected to be available during the fifteen-year study period to develop the 2009-2023 OPPD 15 Year Plan. Attachment 12 lists the supply-side options by size, primary fuel, operational mode, installed capital cost, operating cost and levelized busbar cost. These options include conventional methods of power supply, emerging technologies, storage technologies, and renewables.

The supply-side options in Attachment 12 are categorized into three different types of options: baseload, intermediate, and peaking. Some forms of generation, such as nuclear and large fossil steam units, are well suited for baseload operation because of their relatively low operating cost, even though their installed capital costs are high. Conversely, other forms of generation that have a lower installed capital cost, such as combustion turbines, generally have a higher operating cost (principally due to fuel and heat rate), thus making them appropriate to utilize as peaking units. An example of an intermediate unit would be a combined cycle, which has the flexibility to run at lower or higher capacity factors and retain some degree of economical operation.

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

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

A screening curve is used to determine the relative cost of each option. Those options with the highest construction and operating costs relative to other supply-side options with the same operational mode are eliminated. The screening curve analysis utilized is a plot of the levelized busbar costs versus capacity factor for each technology. Attachment 13A shows the screening curves for baseload options and Attachment 13B shows the screening curves for peaking and intermediate options.

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

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

- Dispatchability

- Timing
- Effects on dispatch of other units
- Forced outages
- Planned maintenance outages
- Coincidence of generation with load
- Existing resource mix

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

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

Peaking Units (0-10% Capacity Factor):
Combustion Turbines
Combined Cycle

Intermediate (15 - 40% Capacity Factor):
Combined Cycle
Pulverized Coal
Integrated Gasification Combined Cycle
Wind Turbine
Fluidized Bed

Baseload (70 - 95% Capacity Factor):
Pulverized Coal
Integrated Gasification Combined Cycle (IGCC)
Fluidized Bed
Landfill Gas
Nuclear

Renewables:
Wind Turbines
Landfill Gas

Not all supply-side options can be evaluated simultaneously in Strategist (computer modeling software) due to computational constraints. The following options have the lowest busbar costs and are evaluated in all cases:

Capacity Purchases	-	Peaking and Baseload
Conventional Pulverized Coal (660 MW Sizes)	-	Baseload
Nuclear	-	Baseload
IGCC	-	Baseload
Combined Cycle	-	Intermediate

Wind Turbine	-	Intermediate
Combustion Turbine	-	Peaking

In recent past years, almost all new power plants in the United States have been natural gas-fired combustion turbines or combined cycle plants. Wind energy is experiencing the most rapid growth in percentage terms of installed portfolio. As mentioned earlier, a number of planned coal fired plants will be brought on-line in the next 1-10 years. At most only a limited number of IGCC and advanced nuclear units will be built in the U.S. in the next decade. These units are further discussed later in this section.

Combined Cycle Conversion of Cass County Station

In general, from an economic standpoint, application of combined cycle technology to an existing natural gas fired plant would result in a lower fuel expense although the operating cost would increase because of the complexity of the process. Converting the existing Cass County Station to a combined cycle unit could be a technically viable option if the conversion is done before 2023.

6.2 Fort Calhoun Station Long Range Projects

Power uprates from various projects at Ft. Calhoun Station are part of the base case IRP. Several major projects were completed during the spring 2005 Ft. Calhoun outage, and additional projects were completed during the 2006 outage. These projects contribute to the continued safe and efficient operation of the station through its licensed period of operation to 2033. The license renewal of Fort Calhoun for 20 years to 2033, approved by the NRC in November 2003, will provide OPPD with a continued diversified fuel mix of approximately 33% nuclear and 66% fossil. Please refer to the 2006 IRP for a description of these projects.

The IRP evaluates the benefits of projects: such as the extension of station life, thermal power uprates and efficiency gains to determine economic feasibility and develop the OPPD 15 Year Plan. Projects selected and approved that provide power uprates to the unit's generation capability are included in OPPD's Load and Capability report in the scheduled completion years. Refer to Attachment 14 to view expected monthly capacity ratings of Ft. Calhoun Station due to the extended power uprate project as well as current monthly ratings.

Rapid Refueling

Removal and installation of the reactor vessel head is labor intensive and time consuming. Modifications to the auxiliaries attached to the head will increase productivity during refueling outages. If no major project upgrades are to be performed in an outage, a refueling outage is expected to take 25-days. This compares to the 35-day refueling outage duration previously achievable. The shortening of refueling outage durations will have an impact on the Strategist modeled dispatch, however impact to the IRP expansion plan due to shorter outage duration is deemed low.

HP Turbine Uprate

The final project which would result in a power uprate would be the replacement of the HP turbine during the fall 2012 refueling outage. The new HP turbine would provide a minimal efficiency gain of 3 MW at the plant's current power level. The maximum benefit of the HP turbine uprate is realized under a reactor power uprate to 1,750 MW-thermal which would provide a 75 MW capacity gain at Ft. Calhoun in July and August and a 79 MW gain in the remaining months. It is currently estimated that this project would cost approximately $165 million in today's dollars.

MAPP Design Review Limits

The operation of the OPPD and regional transmission system is subject to the policies of the Mid-Continent Area Power Pool (MAPP) and after April, 2009, the Southwest Power Pool (SPP). Under MAPP policies the Fort Calhoun Station has a net generation upper limit of 540 MW as approved by the MAPP Design Review Subcommittee. Coinciding with the power uprate of 75/79 MW to be completed in the fall of 2012, is an increase in the transmission limits of Ft. Calhoun Station to a minimum of 559 MW for summer peak conditions and 588 MW for winter season.

6.3 Conventional Pulverized Coal (PC) Option

Pulverized coal units are a mature technology with low variable costs, and moderately high fixed costs that are suitable for base or intermediate load applications. Coal units are required to control air, water, and sold-waste emissions under various state and federal emissions control requirements. The 1979 New Source Performance Standards (NSPS) require new coal-fired units to use flue gas desulfurization (FGD), burner modifications, and electrostatic precipitator or fabric filters to control SO_2, NO_X, and particulate emissions, respectively. The evaluation of this option assumes that each new unit requires scrubbers, low NO_x burners, and baghouses, as well as cooling towers to meet the EPA new source performance standards and the requirements of the 1990 Clean Air Act Amendments. Low-sulfur subbituminous Wyoming Powder River Basin coal is assumed to be the primary fuel. In the 2008 IRP, the base analysis assumes two pulverized coal options, a joint unit at Nebraska City of 660 MW and a 300 MW share of a 600 MW greenfield unit.

Emissions control strategies at the various plants currently under development across the country differ, but all will have to meet extremely tight regulation levels. Pulverized coal generating units can achieve comparable (or possible lower) SO_2 and NO_X levels to IGCC and can be made CO_2-ready in anticipation of carbon regulations. Please see Table 6 for a comparison of typical emissions from an IGCC plant to the expected emissions from Nebraska City Unit 2.

Currently, IGCC is approximately $750/kW higher in capital costs compared to building Nebraska City Unit 3. However, in general capital costs for PC plants are increasing due to tightening environmental regulations, while IGCC capital and O&M costs are expected to decrease with design standardization, technological maturity and cycle efficiency improvements.

Please see Appendix A for an overview of pulverized coal technology.

6.4 Coal Gasification/IGCC Option

In recent years, there has been considerable world-wide interest in coal gasification for power generation. Across the U.S. there are several integrated gasification combined cycle (IGCC) units under development. In the 2008 IRP, analysis was completed to determine the feasibility of installing a 521 MW IGCC unit (with a 300 MW share for OPPD) as an option for baseload capacity (in lieu of a 300 to 660 MW baseload conventional coal unit).

Please see Appendix A for an overview of IGCC technology.

Previous Demonstration Projects and Current Plans

At present, only two utility-size IGCC plants exist in the U.S. The 262 MW Wabash River Plant (Indiana) is a repowered 90 MW pulverized coal unit. The 250 MW Polk Plant (Florida) is a greenfield project. Both of these units are heavily subsidized, one-of-a-kind demonstration projects. The lack of a standard design has made this technology extremely expensive, but commercially available 500 to 600 MW standard designs are expected to emerge and reduce capital costs.

Environmental Issues and Air Emissions

IGCC technology promises reduced emissions of sulfur and nitrogen oxides, mercury and particulates when compared to traditional pulverized coal (PC) power plants. Typical emissions from an IGCC plant are compared to expected emissions from Nebraska City Unit 2 in Table 6. The IGCC emissions shown in Table 6 represent typical values from the Polk and Wabash demonstration projects. It should be noted that mature IGCC technology could produce emissions less than those that are shown. Also note that the limits shown for Nebraska City Unit 2 may not represent the actual performance of the unit. It would be expected that actual emissions would be less than permit limits. As illustrated in Table 6, IGCC emissions are not significantly different than expected emissions from Nebraska City Unit 2. Specific mercury emission controls remained unresolved for IGCC, but it is reported that mercury capture is significantly less costly for an IGCC unit. Considering the lack of clear understanding of mercury capture methods, or emission limits related to mercury, it is too early to predict whether IGCC has an advantage over PC in this area.

Table 6 – Comparison of IGCC Emissions to NC2 Emissions

	IGCC Emissions (lb/MMBTU)	NC2 Permit Limits (lb/MMBTU)
PM	0.0121	0.018
SO_2	0.0802	0.100
NO_X	0.0902	0.070
CO_2	213	213

Carbon Sequestration Opportunities

CO_2 emissions from IGCC parallel that of a PC with IGCC's slightly lower heat rate reducing CO_2 emissions on a lb/KWh base. After the gasification stage in an IGCC, it is possible to convert carbon-monoxide to CO_2 and capture, but this is an exothermic reaction and reduces the heat content of the gasification syngas and would negatively impact the overall IGCC heat rate. An existing coal gasification plant in North Dakota does convert CO from the syngas stream to CO_2. This facility sells the CO_2 to the oil industry and the syngas to other users – syngas is not used for electrical generation at the facility. Future commercial IGCC plants may achieve CO_2 capture and sequestering systems.

IGCC Conversion of Cass County Station

Converting the existing Cass County Station to an IGCC unit could be a technically viable option, and OPPD has received some very high-level estimates on what such a conversion might cost. Estimates obtained from vendors show that it would cost an additional $3/MMBtu above the price of coal for the equipment to convert the coal to gas. One benefit of using coal-derived gas is that it would shift reliance on a fuel with a highly volatile cost (natural gas) to a fuel with more stable cost (coal).

6.5 Advanced Nuclear Option

The passage of the Energy Policy Act of 2005, along with several other factors, such as a restructured licensing process, availability of advanced reactor designs, global climate change concerns and the need for new baseload capacity have made new nuclear construction a more feasible option throughout the United States. Volatile natural gas prices adds economic uncertainty in installing a combined-cycle, natural gas-fired unit. Increased regulation of CO_2 and other emissions will likely create additional barriers to baseload gas- and coal-fired plant construction. Carbon taxes have the potential to make nuclear more cost effective as compared to gas or coal-fired units. Many U.S. utilities are studying the option of adding new nuclear capacity to their generation portfolio. In the 2008 IRP, analysis was completed to determine the feasibility of purchasing a 300 MW share of

an advanced nuclear unit as an option for baseload capacity (in lieu of a 330 MW share of a 660 MW baseload conventional coal unit).

Please see Appendix A for an overview of advanced nuclear Technology.

Estimated Nuclear Plant Costs

There is substantially less certainty about cost estimates for nuclear plants as compared to pulverized coal plants. The capital cost of an AP1200 advanced nuclear design power plant is estimated at $3,719/kW (2009$'s). This is the cost of the plant only. The installed capital cost is $6,308/kW. The AP1200 levelized busbar cost, operating baseload in the Midwest U.S., is 5.1 cents/kWh which includes decommissioning, transmission, owner costs, fuel, operations and maintenance and interest. The production plant cost and operating and maintenance costs are from a study completed by Enercon for a group of Midwest utilities including OPPD. The estimated O&M cost is for a single AP1200 unit at an existing site.

Drivers for Future Nuclear Units

There are a number of regulatory, economic, technological, and environmental drivers that appear to make nuclear units more viable in the future.

The DOE Nuclear Power 2010 program, unveiled in 2002, is a joint government/industry cost-shared effort to identify sites for new nuclear power plants, develop and bring to market advanced nuclear plant technologies, evaluate the business case for building new nuclear power plants, and demonstrate untested regulatory processes leading to an industry decision in the next few years to seek Nuclear Regulatory Commission (NRC) approval to build and operate at least one new advanced nuclear power plant in the United States. The DOE is actively engaged with the industry to address the issues affecting future expansion of nuclear generation.

The Energy Policy Act of 2005 could also be a catalyst for the construction of new nuclear units. The Act authorizes a production tax credit of 1.8 cents per kilowatt-hour for 6,000 MW of qualified advanced nuclear power facilities for an 8-year period after beginning production. This incentive is authorized through 2020, subject to annual limitation of $125 million per 1,000 MW per taxable year. The Act also authorizes $1.25 billion for fiscal years 2006 through 2015 to fund a prototype Next Generation Nuclear Plant Project to produce both electricity and hydrogen. The prototype nuclear reactor and associated hydrogen plant is to be sited at the Idaho National Laboratory (INL) in Idaho.

Future CO_2 legislation could be a major driver to construct new nuclear units. A future CO_2 emission reduction target may not be met just by renewable energy, retiring older coal units and switching to natural gas. New nuclear generation may assist in meeting such targets.

6.6 Wind Energy Option

The 2008 IRP extensively analyzed cases using the actual capital costs and estimated

O&M costs from actual project wind costs OPPD has observed. High and low sensitivity cases were also considered. These cases are discussed in Section 9.3.

Key Issues and Cost Uncertainties

There are significant issues and cost uncertainties that must be addressed and considered before building large-scale wind energy facilities. There are environmental and social issues which include public acceptance, siting, permitting, land use, visual and noise impacts, and the impact on bird populations. Furthermore, wind generation is not dispatchable and it must be absorbed by the grid when generated. As wind energy facilities become larger, it is likely that system operation will be significantly impacted which could result in additional scheduling and unit commitment costs.

There are potentially large transmission costs to upgrade the existing transmission system to accommodate a large wind energy facility. These costs are very site dependent and could be very substantial depending on the size and location of the facility.

Cost Estimates

The actual construction costs obtained from regional Midwest wind projects and operational experience of the Ainsworth Wind Energy Facility have provided actual project specific information for estimating the cost of future wind energy facilities in Nebraska. The total cost of energy produced from a wind facility is very dependent upon the capacity factor achieved, and to a lesser extent, on the on-going O&M expenses. As of September 2008, Ainsworth achieved three years operation. OPPD will continue to closely monitor all of the costs of operating the Ainsworth Wind Energy Facility.

7.0 Demand-side Management Programs

Demand Side Management Programs (DSM) consist of electric utilities planning, implementing, and monitoring activities designed to encourage customers to modify their levels and patterns of energy consumption. DSM programs are implemented to achieve two basic objectives: energy efficiency and load management.

These programs generally fall into three main categories (or some combination thereof):

1. Conservation programs which reduce energy use through improved efficiency
2. Load management programs which shift energy demand through direct load control, time-of-use rates, interruptible rates, or use of customer-owned generation to reduce or eliminate their native load
3. Strategic load growth programs which increase energy use during certain periods, such as programs that encourage cost-effective electrical technologies that operate primarily during periods of low system demand

DSM programs are generally considered beneficial to all customers and the utility–not just those customers participating in a specific DSM program. Successful DSM programs may delay supply-side resource additions or better optimize resource utilization through conservation programs and load-shape modifications. DSM programs that increase energy conservation also have a positive impact on the environment by lowering emissions from existing generation facilities.

7.1 Heat Pump Programs

OPPD has implemented both Residential and Commercial Heat Pump programs. These programs result in off-peak load building in the winter months along with peak reduction for the summer months. These DSM programs are included as a reduction (or increase) to the base, load forecast.

The Residential Energy Conservation Program (RECP) is designed to help customers save energy throughout the year by giving them incentives to install high-efficiency heat pumps. Customers who install qualifying equipment receive Energy Credit Refunds and a special winter electric rate. In addition, OPPD will inspect new systems and verify that they are operating efficiently and economically.

Through its Commercial Heat Pump Program, OPPD offers a full spectrum of turn-key geothermal and water-source heat pump design solutions for commercial facilities. OPPD offers rebates for each installed ton of heat pump cooling capacity. The Environmental Protection Agency has named the geothermal heat pump system as the most efficient heating and cooling system available today.

7.2 Curtailment Load Programs

OPPD Rate Schedules 260 and 467 gives customers the option to participate in a mandatory curtailment program in exchange for a lower rate. This program has 2 accounts that provide for a load reduction of 4.1 MW.

OPPD Rate Schedule 469W provides customers the option to participate in a time of use rider in exchange for a lower electric rate. This program has 4 accounts that provide for a load reduction of 12.2 MW.

OPPD Rate Schedules 467V and 467E gives customers the option of voluntarily curtailing a minimum of 100 kW of demand at one service location when requested by the District. Approximately 22 accounts have volunteered for this rate schedule. This provides an additional 45.9 MW of voluntary load reduction.

7.3 Emergency and Standby Generator Program

OPPD has developed a unique program to partner with customers who have emergency standby generators installed. This program benefits OPPD customers by providing cash flow on the investment in the generator and it benefits OPPD by providing diversification in generation. Under these agreements, when demand for electricity is high or when unexpected outages occur, customers use their on-site generation to either reduce or eliminate energy they would normally receive from OPPD (their native load). OPPD has agreements with customers representing 41 accounts which results in a total load reduction of 41.4 MW.

The curtailable load programs along, with the Emergency and Standby Generator Program, will continue to provide OPPD with about 60 MW of curtailable load in the upcoming years.

7.4 Rebuild America Project

OPPD, the Nebraska Energy Office, and the University of Nebraska have worked together to encourage Nebraska businesses to invest in energy-efficiency improvements through the Rebuild America program. This program is administered by the U.S. Department of Energy and was formed to improve energy efficiencies in major commercial buildings throughout the U.S.

In September 2003, OPPD, in partnership with the University of Nebraska, received a Rebuild America grant. The objectives of this project were to make Nebraska one of the top 10 Energy Star Building states, demonstrate the Continuous Commissioning Leading Retrofit Process (CCLRP), and attract private funds to improve energy efficiency in the commercial sector. This project has exceeded all objectives and goals and made some very significant achievements.

7.5 Energy Research Partnership

OPPD and the University of Nebraska Omaha (UNO) have formed an energy research

partnership that will focus on exploring how new technologies can help individuals and businesses reduce their energy use. This program is known as the Energy Saving Potential (ESP) program. Through the ESP program, UNO faculty, students and staff will examine energy conservation through research, model-testing, public policy analysis and development and assessment of pilot programs and services. Applying new technologies to conserve energy can cut costs for both OPPD and OPPD's customer-owners. OPPD will fund ESP up to $500,000 annually through 2010.

7.6 Evaluation by DSM Strategic Issues Team

OPPD is a long-time supporter of DSM programs, and the implementation of these programs is a corporate strategic initiative. The existing DSM programs continually undergo review and modifications. Recent years have seen many very significant changes in the electric power industry including the role DSM programs have in achieving energy conservation and load management. To increase OPPD's focus in this area, the Sustainable Energy and Environmental Stewardship (SEES) Division was formed at OPPD in 2007. A SEES initiative created a DSM team composed of OPPD personnel to create a long term centralized plan for DSM programs.

The process will include identifying new energy conservation technologies and load management programs, qualitative screening, estimates of peak demand impacts, determining load modifying effects; and estimating program life expectancy, cost and validation methodology. The best DSM options will be developed and quantitatively evaluated as DSM options in the IRP. Furthermore, the DSM team will assess the effectiveness of OPPD's current DSM and load curtailment programs and further analyze load curtailment projections. This would include projections of the demand-side savings of large customer projects, and analysis of whether additional load curtailment agreements are in the best interest of the District. Table 7 shows the programs for which business plans have been developed and approval to pursue have been given. Some of these programs will be modeled in the future using Strategist.

Table 7 – OPPD's Targeted DSM Programs

Residential Programs	**Commercial & Industrial Programs**
Lighting – CFL	Time of Use Rates –Expanded
Time of Use Rates – Study	Lighting and Motor Efficiency - Pilot
Heat Pump - High Efficiency	Curtailable Program – Enhanced
AC Load Control – Study & Pilot	Innovative Technologies – Pilot
Energy Star Qualified Home Energy Rating	Energy Star - Pilot
Home Air Leakage Test	

7.7 EPRI DSM Manager Options Modeled

Existing evaluation of four DSM programs are used in the IRP analysis. These programs were selected from a previous review of EPRI's literature on successful DSM programs. These programs can be characterized as peak clipping, load shifting, valley filling, conservation, or some combination thereof. DSM programs selected were initially evaluated using DSM Manager, an EPRI evaluation tool. DSM Manager assists in building the program load impact data. Following the review of many of the programs in DSM Manager, four programs were chosen that provide desirable conservation and load-modifying effects. The programs studied and their impact on system demand if fully implemented, are shown in Table 8. These programs were modeled as options in the 2008 IRP. The Strategist results of these options are shown in Attachment 15, and the results are discussed in Section 8.

Table 8 - Impact of Proposed EPRI DSM Manager Programs

(Load at Customer Level)

Proposed Program	Demand Reduction (MW)	Program Impact
Air Conditioner (A/C) Cycling	55	Peak Clipping
A/C Setback Thermostat	40	Peak Clipping/Conservation
A/C Tune-Up/Cleaning	16	Peak Clipping/Conservation
Commercial Efficient Lights	5	Conservation

8.0 The OPPD 15 Year Plan and Suboptimal Plan Analysis

This section discusses the OPPD 15 Year Plan and analyzes several suboptimal plans and other alternatives.

8.1 The OPPD 15 Year Plan

The construction of the 663 MW Nebraska City Unit 2 is on schedule and expected to be completed May, 2009.

The OPPD 15 Year Plan recommends several power supply additions over the next 15 years as shown in Table 9.

Table 9 – OPPD 15 Year Plan

Year	Resource Addition	Reason
2009	663 MW Nebraska City Unit 2 – 331.5 MW for OPPD	Load Growth
2011 – 12	Peaking Capacity Purchases	Load Growth
2013	75 MW, FC HP Rotor Power Uprate – Project Completed during Fall 2012 Outage	Load Growth
2014	Cass County Conversion to Combined Cycle	Load Growth
2019 – 20	Peaking Capacity Purchases	Load Growth
2021	160 MW Peaking Gas Turbine	Load Growth
2023	660 MW Nebraska City Unit 3 – Coal-Fueled, 330 MW for OPPD	Load Growth

The 2008 IRP considers wind resources in increments of 100 MW wind farm additions at 40% CF locations. The recent increases in wind energy equipment costs have made wind uneconomical in the 2008 IRP expansion plan optimization. Wind energy options may be needed in upcoming OPPD 15 Year Plans dependent on the implementation of either a state or federal RPS; as a carbon tax is stepped-in at a higher cost than assumed in the 2008 IRP base case evaluation and if wind equipment costs decrease.

Other Purchase and Sales

OPPD has a firm capacity purchase contract with the Western Area Power Administration (WAPA) through 2020. OPPD also provides firm wholesale service to Syracuse, Greenwood, Elk Creek, and Tecumseh. All of these transactions are shown in Attachments 1 and 2.

8.2 Unit Participation Option

Seven parties have entered agreements for a long-term participation share of Nebraska City Unit 2, a 663 MW baseload coal-fired unit.

The current budget is based on the least-cost plan to install a 663 MW baseload coal-fired unit in 2009. A third unit at Nebraska City Station is provided as an option in the Strategist model, this third unit is selected as part of the OPPD 15 Year Plan in 2023. There is greater operational risk associated with a larger 660 MW unit. However, it is more economical to build a 660 MW unit that can provide 330 MW of capacity to serve OPPD retail customers and 330 MW to serve other utilities. Furthermore, like Nebraska City Unit 2, a 660 MW unit can offer some savings in capital costs and fixed O&M costs compared to a smaller unit. However, additional analysis is required to determine the optimum number of units and total capacity of Nebraska City Station. The existing Nebraska City Unit 1 is consistently among the lowest cost coal-fired plants in the country. OPPD expects Nebraska City Unit 2 to also be extremely cost competitive.

Nebraska City Station Assumptions

The current assumption is that Nebraska City Station is limited to three units. After Nebraska City Unit 3, if installed, the only remaining conventional coal option in the Strategist model is a 600 MW greenfield unit, 300 MW would be OPPD's.

8.3 Retirement of Existing Units

A key consideration in power supply planning is the retirement of existing generating plants. Most new thermal generating units are built for a normal useful life of 40 to 50 years. All of OPPD's existing baseload units have been in service for more than 25 years. In the 2006 IRP, it is assumed that Nebraska City and North Omaha units will be retired after 75 years. The commercial operation dates and retirement years for OPPD baseload units are shown in Table 10.

Table 10 – Age of Existing Baseload Units

Baseload Unit	Commercial Operation Year	Current Age (Years)	Planned Retirement Year	2008 Summer URGE Rating (MW)
North Omaha 1	1954	54	2029	78.6
North Omaha 2	1957	51	2032	111.0
North Omaha 3	1959	49	2034	111.0
North Omaha 4	1963	45	2038	138.2
North Omaha 5	1968	40	2043	224.0
Fort Calhoun	1973	35	2033	476.0
Nebraska City 1	1979	28	2054	646.0

Based on the current assumptions, Fort Calhoun, and North Omaha Units 1, 2, 3 and 4 will be retired within the 30-year study period of the 2008 IRP (2009-2039).

With proper operating and maintenance practice, older generating units are capable of continued reliable operation. However, as components of older generating units fail, it is increasingly difficult to procure replacement parts and, in some cases, it is not cost effective to repair the units.

As the age of units approach 40-years-old and greater, and even if they have been well-maintained, at some point in the future it may be more economical to retire units rather than continue operation. This is especially true if new environmental measures are enacted which may require additional expenditures to allow these units to comply.

Long-term engineering studies are typically required to confidently predict: 1) remaining life, and 2) if expenditures above and beyond those expected are needed to maintain the units in their present state. Studies of this type may become more prevalent as units age and resource planning horizons are extended.

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

System Security

The North Omaha units support voltage on the Omaha metropolitan transmission lines to the benefit of OPPD's system operational security. System security in this sense relates to how well the system can maintain stable operation under transmission system line trips caused by storms, tree contact, etc. As retirements of North Omaha units are considered, maintaining a certain level of generation capacity at the North Omaha Station physical site will remain a consideration.

8.4 Diversity

Ft. Calhoun Station being nuclear power adds fuel diversity to OPPD's generation portfolio. Without Ft. Calhoun it's conceivable that upwards of 90% of OPPD's electricity would be generated by coal. With potential costs being placed on carbon emissions as well as required mercury emission reductions and ongoing limits on SO2 and NOX, having a 30% contribution towards annual system requirements from nuclear, places OPPD in a position of a softer landing as further restrictions on fossil fuels come to pass. The 75 MW capacity addition at Ft. Calhoun which is part of the OPPD 15 Year Plan will assist in maintaining the accustomed contributions from nuclear power even as OPPD customers consume more energy. The conversion of Cass County to a combined cycle unit will allow that station, which is fueled by natural gas to operate as an intermediate capacity unit which should lessen coal fuel's percentage of system requirements. Though fossil fueled, a natural gas fueled combined cycle with its high thermal efficiency will emit CO_2 at rate of approximately ½ of a pulverized coal plant producing the same amount of electricity. Risk resulting from having too high of a reliance on just one fuel-type is a key consideration for diversity. The OPPD 15 Year Plan considers wind energy but is currently uneconomical in the 2008 IRP.

8.5 Reliability

Nebraska City Unit 2 being a subcritical conventional pulverized coal unit is expected to be highly reliable. Reliability was a major factor in choosing this technology to meet OPPD growing baseload requirements beginning in 2009. Coal is the fuel for approximately 65 - 70% of OPPD customer electricity usage. Omaha is in relative close proximity to large coal reserves in the Powder River Basin. Considering fuel supply and deliverability, coal is a very viable fuel for OPPD. Rail transportation reliability has been an issue but completed improvements to rail lines connecting the Power River Basin have apparently alleviated the problem. The disruptions in coal delivery experienced in 2007 ware no small affair as some utilities saw their coal storage nearly exhausted. A positive outcome was a heightened awareness of how critical this transport infrastructure is to America's energy security. The OPPD 15 Year Plan provides a 13.64% capacity reserve margin. The 13.64% margin is established by SPP reserve sharing members and is critical in maintaining continuous electricity deliverability to regional consumers as well as the eastern interconnection.

8.6 Dispatchability

OPPD dispatches units to meet control area obligations and net interchange schedule while retaining reserve requirements. A forecast of expected OPPD retail load is produced daily

and establishes base levels of expected generation. Due to unpredictable daily variables, units will be dispatched in real time to maintain acceptable levels of interconnected operation. Baseload generating units under automatic control are economically dispatched. The exact time of start-up and shut down of peaking units is decided by OPPD energy marketing personnel. OPPD's portfolio of wind generation is small enough that its impact on dispatch is negligible. Future wind integration into OPPD control area by direct interconnection or pseudo-ties will present new challenges in the system dispatch. The IRP process will incorporate aspects of large-scale variable generation, likely wind, on the dispatchability of the system.

8.7 Other Risk Factors

The utility industry is entering an era when there will be unprecedented loss of qualified personnel through retirements. OPPD has investigated and implemented succession plans. OPPD has implemented training programs for generation dispatch and control and balancing area operations so less experienced personnel can gain and maintain operational expertise in efficient and consistent fashion. Awareness of threat from physical or cyber intrusion is high. All personnel are required to complete security training annually which addresses facility and computer security.

8.8 Suboptimal Supply-side Cases

Many of the supply-side technologies that were not selected in the base case or those that were eliminated during the screening process have been evaluated as suboptimal cases in Strategist. The results are shown in Attachment 15. In these suboptimal cases, the technology option is forced during the 2009 through 2023 time period. The pumped storage and advanced battery technologies show a lower NPV cost than the base case. This is probably due in large part to the forecasted increase in capital costs for the coal unit in the base case. Nonetheless, these technologies are not considered feasible for OPPD. Most of the available sites in the U.S. for pumped storage are already in use. The possibility of new pumped storage facilities is very limited. Several new battery chemistries are being considered. However, none of them is at a high-level of development for utility scale applications at this time.

Suboptimal DSM Cases

Of the four Demand-Side Management (DSM) options, the commercial efficient lighting has a slightly lower NPV. Commercial efficient lighting is considered an economically effective program at a NPV, $25 million less than the OPPD 15 Year Plan. However, commercial customers are installing high efficiency lighting on their own without any rebates or incentives from OPPD. The other DSM programs have a higher NPV than the benchmark case and they would not delay the need for the future baseload unit in 2023. AC Cycling and AC Setback will delay the Cass County conversion to 2015. The Strategist results of these options are shown in Attachment 15.

8.9 Suboptimal Future Baseload Options

The 2008 IRP, Strategist optimization evaluates 30 years into the future to develop the OPPD 15 Year Plan. Table 11 shows several suboptimal resource options. Three of the plans shown, one of which is the OPPD 15 Year Plan, include pulverized coal at Nebraska City Station as the next baseload. The years of this install are either 2020, 2023 or 2024. Coal in 2020 is slightly more in NPV cost than the OPPD 15 Year Plan. Waiting until 2024 will cost slightly more than the OPPD 15 Year Plan. If the next baseload unit is an advanced nuclear unit installed in 2023, the plan is 3.5% higher in NPV than the OPPD 15 Year Plan. The installation of an IGCC as the next baseload in 2023 costs 0.8% more in NPV. Nuclear Only is a suboptimal case that allows future baseload units to be only nuclear through the 30 year evaluation period and costs an additional 28.6% in NPV. The advanced nuclear and IGCC options are discussed in Section 6.

Table 11 – Suboptimal Options Analysis

Description	Additional Capacity (MW)	Year of Baseload Unit	NPV 2009 m$'s	Change from 15 Year Plan	Change from 15 Year Plan
OPPD 15 Year Plan	330	2023	$10,027	$0	0%
Coal in 2020	330	2020	$10,031	$4	< 0.1%
Coal in 2024	330	2024	$10,044	$17	0.2%
Adv Nuclear in 2023	300	2023	$10,373	$346	3.5%
IGCC in 2023	300	2023	$10,112	$85	0.8%
Nuclear Only	300	2023	$12,896	$2869	28.6%

Attachment 18 shows the expansion plans through year 2026 of the OPPD 15 Year Plan, the Adv Nuclear in 2023 and IGCC in 2023 plans as well as other sensitivity and wholesale market scenarios discussed in Sections 9 and 10.

8.10 Summary and Conclusion

The OPPD 15 Year Plan requires a new baseload unit in the 15th year, year 2023. This would be a pulverized coal unit at Nebraska City Station. The Strategist optimization shows commissioning Nebraska City Unit 3 in the period of 2020 to 2024 is an economical option. The 2008 IRP recommends the specific year to be 2023 for the Nebraska City Unit 3 based on 4 key considerations. The effects on OPPD customer-owner rates upon financing the debt of a baseload coal unit are thought to be high enough that forgoing any earlier installation before 2023 is prudent. The OPPD sustainable energy and environmental stewardship initiative has potential to slow growth in retail load demand, delaying by one or

two years the need for a baseload unit. The uncertainty of knowing the type of regulatory structure carbon will be under upon plant completion. The increasing politicization of the approval process to build coal plants makes certainty of receiving approval a significant risk. The 2008 IRP is basing the capital costs of pulverized coal on projections from the Ventyx 2008 Spring Outlook report. These cost estimates are considerably more than the cost of constructing Nebraska City Unit 2 which is to be commissioned May 2009. Two other technologies merit close consideration as options to pulverized coal. These options are advanced nuclear and coal gasification used with combined cycle, commonly referred to as integrated gasification combined cycle (IGCC). Appendix A has descriptions of these technologies. These options have received increased attention with growing concerns over greenhouse gases combined with the electric power industry's role as a greenhouse gas contributor.

Integrating coal gasification with large-scale electrical generation has, so far, been limited to only a few prototype sites around the country. IGCC presents a technology risk for stakeholders. On the other hand, IGCC could provide a regulatory risk hedge against future environmental compliance costs. Considering the unproven nature of the technology, the advancement of IGCC technology for large-scale electrical generation will require significant capital expenditures at an elevated level of risk. IGCC utilizes integrated processes and heat transfers between these processes to achieve desired efficiencies. At this stage in development, concern exists about IGCC's ability to operate at the high capacity factor needed for baseload requirements. Several IGCC projects have been announced around the country as some utilities are eager to demonstrate "clean coal" technology. Clean coal power (IGCC) technologies received incentives in the 2005 Energy Policy Act.

Among the currently operating electric power nuclear units in the U.S. most were brought on line before 1980. A U.S. utility, presently operating a large nuclear fleet, is a likely candidate to construct the first of what would become a new generation of advanced nuclear reactors for electric power generation. The earliest in this new generation of nuclear units would be entitled to incentives in the 2005 Energy Policy Act.

The costs for all three of these options are very site-dependent and case-specific. An additional unit at an existing site is usually less expensive than the first unit because of the savings in common equipment required for the plant (e.g., land, coal handling, and water intake structure). Nebraska City Unit 3, a 660 MW unit, offers advantages over a greenfield site. However, additional analysis is required to determine the optimum number of units and total capacity of Nebraska City Station.

As previously discussed, uncertainties in future power supply costs, environmental regulations, and load growth will have a significant impact on the final resource selection and total cost.

9.0 Sensitivity Analysis

This section discusses and analyzes several sensitivity cases. These cases include benchmark sensitivity analysis, environmental sensitivity cases and wind energy sensitivity cases.

9.1 Benchmark Case Sensitivity Analysis

Sensitivity studies performed for the 2008 IRP determine the impact on key data assumptions on the economic viability of performing the power uprate at Ft. Calhoun Station in which capacity becomes available in 2013 and the conversion of Cass County to combined cycle in 2014 (as well as future additions). Table 12 shows sensitivities of the OPPD 15 Year Plan to OPPD's load growth, wholesale market pricing, RPS and zero carbon tax. The sensitivity cases shown in Table 12 along with additional sensitivity cases are shown in Attachment 16.

In the 2008 IRP sensitivity analysis the only year the Ft. Calhoun power uprate is allowed to be accomplished is during the 2012 fall outage, therefore the project is either selected for availability in 2013 or not selected at all. The conversion of Cass County is allowed in years 2014 – 2023 and therefore can be delayed from the year in which it is part of the OPPD 15 Year Plan, 2014, to a later year, or not selected at all.

The 2008 IRP sensitivity analysis demonstrates a decrease in the wholesale market price of 40%; debt-service coverage of 1.7; no carbon tax; or very low gas costs of $6.83/MMBtu will make the Fort Calhoun power uprate uneconomical. A low load growth rate in retail sales of 1.0% per year will delay the conversion of Cass County by seven years to 2021. A very high carbon tax scenario delays the conversion of Cass County by two years, to 2016. Sensitivities without interchange sales delay the conversion of Cass County two years, to 2016; as will a sensitivity of a 15% RPS with no carbon tax. A 15% RPS requires 600 MW of wind. A 15% RPS with the base case carbon tax will delay the conversion of Cass County by one year, to 2015. Sensitivity to natural gas costs shows the Ft. Calhoun power uprate and the conversion of Cass County in 2014 to be unaffected by small decreases and large increases in the natural gas forecast.

The 2008 IRP assumes a CO_2 tax of $5/ton beginning in 2012, adding about $1/ton a year until $23/ton is reached in 2032. The high CO_2 tax case reaches $35/ton by 2032. The very high CO_2 tax case increases the CO_2 tax to $46/ton by 2032. (For each $1/ton of CO_2 taxes, the cost of coal-fired generation increases by about $1/MWh.) See Table 13 for the carbon tax assumptions of the base case and the four sensitivities. As shown in Table 12, a zero carbon tax case lowers the NPV from the OPPD 15 Year Plan by a considerable amount of 18.5%. Though the Fort Calhoun power uprate is uneconomical in the zero carbon tax case, if the power uprate is completed in a zero carbon tax scenario the power uprate only adds an extra $4 million in NPV.

Examining all sensitivity cases in Attachment 16 shows adjusting both coal and natural gas

fuel costs (except for very low gas), adjusting coal station capital costs and adjusting the carbon tax (except for very high tax) do not sway the need for the Ft. Calhoun Station power uprate in 2013 and the conversion of Cass County in 2014. The need to build these two projects appears fairly assured at this point in time. By comparison, the timing or need of the next baseload unit, Nebraska City Unit 3 in the OPPD 15 Year Plan, is more susceptible to change under the 2008 IRP sensitivity analysis. A high load growth will move this baseload need up three years to 2020. Variances in the wholesale market impact the baseload need. Low wholesale prices will delay the need, high wholesale prices will move up the need for this baseload unit. Higher coal costs of 30 cents/MMBtu will delay the baseload need until 2029. Very high coal costs will replace the pulverized coal option with a combined-cycle plant. Low natural gas prices will also require a combined cycle (in addition to the Cass conversion) and delay the baseload option. High natural gas prices will move-up the need of the next baseload unit by one or two years to 2021 or 2022.

It is important to note that these are very high-level sensitivity studies–only single variables are changed in each scenario. They are useful in demonstrating that it would take significant changes in existing forecasts to alter the resources specified in the OPPD 15 Year Plan.

Table 12 – Load Growth, Wholesale Market, RPS and Carbon Sensitivity Case Analysis

Case #	Description	FC Power Uprate-Yes or No	Cass County Conversion —Year or No	NPV 2008 m$'s	Change from Benchmark	Change from Bench-mark
B01	OPPD 15 Year Plan	Yes	2014	$10,027	$0	n/a
B04-S08L	Low Load Growth Forecast 1.0%	Yes	2021	$8,038	$(1,989)	(19.8)%
B04-S08H	High Load Growth Forecast 2.5%	Yes	2014	$12,603	$2,576	25.7%
B02-S12L	40% Reduction in Wholesale Prices	No	2014	$10,162	$135	1.3%
B04-S09L	20% Reduction in Wholesale Prices	Yes	2014	$10,383	$356	3.6%
B02-S9H	20% Increase in Wholesale Prices	Yes	2014	$9,346	$(681)	(6.8)%
B02-E3	No Interchange Sales	Yes	2016	$10,798	$771	7.7%
B02-E1	No Interchange Purchases	Yes	2014	$10,107	$80	0.8%

B02-E2	No Interchange Sales or Purchases	Yes	2016	$10,957	$930	9.3%
B05-R15	15% RPS	Yes	2015	$10,154	$127	1.3%
B06-C01N	No Carbon Tax	No	2014	$8,170	$(1,857)	(18.5)%
B06-C01PU	No Carbon Tax, Require FC PU	Yes	2014	$8,174	$(1,853)	(18.5)%

9.2 Benchmark Sensitivity Cases for Carbon Pricing

In the 2008 IRP, sensitivity analysis was completed to determine the impact that carbon costs would have on the benchmark, baseload generation resource. The carbon pricing assumptions are shown in Table 13.

Table 13 – Carbon Pricing
($/Ton of effluent)

	No Carbon Cost	Low Case	Base Case	High Case	Very High Case
2012	0	3	5	8	10
2013	0	4	7	11	14
2014	0	4	8	12	16
2015	0	5	9	14	18
2016	0	5	10	15	20
2017	0	5	10	15	20
2018	0	6	11	17	22
2019	0	6	12	18	24
2020	0	7	13	20	26
2021	0	7	14	21	28
2022	0	8	15	23	30
2023	0	8	15	23	30
By 2032, Increases to:	0	12	23	35	46

The results of how these higher emissions costs change the OPPD 15 Year Plan are shown in Attachment 16.

It is important to note that these increased environmental emission costs are used for very high-level sensitivity studies. They are useful in demonstrating the magnitude of change that it would take in existing forecasts to alter the next baseload coal unit in the benchmark plan.

9.3 Wind Energy Sensitivity Cases

The OPPD 2008 IRP used additional sensitivity cases to demonstrate the sensitivity of wind energy feasibility to variations in assumptions. See cases as listed in Attachment 17.

In the 2008 IRP optimization, no 100 MW large-scale wind energy facilities were chosen as part of the OPPD 15 Year Plan.

The economic feasibility of wind energy is largely a function of production tax credits and other incentives, the capacity factor, and the prevailing wholesale energy market. A 400 MW wind energy installation based on current wind costs in the Midwest, and located in out-state Nebraska (40% capacity factor), is only $13 million NPV more expensive than the OPPD 15 Year Plan. Adding 100 MW, the most optimum year is 2014, adds $13 million in NPV; to go from 100 to 400 MW is no extra cost in NPV. Adding 200 MW of wind actually costs more than both the 100 MW and 400 MW case and costs $17 million in NPV more than the OPPD 15 Year Plan.

Though the 100 MW wind facility is not part of the OPPD 15 Year Plan, the 2008 IRP analysis shows slight reductions in the cost of wind equipment (turbines, towers, etc.) makes wind economical in large amounts. A decrease in levelized costs of $5/MWh makes 400 MW of wind economical. A decrease in levelized costs of $10/MWh makes 600 MW of wind economical. Previous OPPD IRPs have shown the economic justification of wind energy can be sensitive to variations in wholesale market prices. However, the 2008 IRP finds that variations in wholesale market prices do not make wind energy economical.

10.0 Scenario Analysis

A variety of scenarios are analyzed in the 2008 IRP. Scenario development involves the iterative development of plausible alternative views of the future given different economic, regulatory, and technological driving forces. Scenario analysis is a proven tool to better anticipate and respond to future risk and opportunities. These scenarios are intended to provide a framework for further analyzing strategic issues and options. An evolving markets issues team identified alternative scenarios for development of the wholesale market and outlined the forces driving each of these scenarios. These scenarios were developed based on the changing industry market structure and dynamics. These scenarios are modeled as alternatives in Strategist for the 2008 IRP.

10.1 Alternative Scenarios - Evolving Wholesale Markets

An OPPD evolving market issues team provided to senior management recommendations to help ensure appropriate strategies are in place to mitigate risks and capitalize on opportunities in the wholesale market. The evolving markets initiative identified alternate scenarios for the wholesale market going forward. The scenarios factor alternate assumptions in industry market structure and dynamics as well as identifying the forces driving these changes.

Among the recommendations made by the issues team was to consider and develop assumptions for the key factors identified and provide them for input into the IRP. By modeling these assumptions in the IRP, OPPD can further quantify the monetary impact of each of these scenarios on overall OPPD costs.

Market Dynamic Drivers

Market dynamics include changes in demand and supply driven by anticipated trends in fuel, technology, legislation and consumer attitudes. It was determined that future wholesale revenues will depend on the following market dynamic drivers:

- The Structure of the Transmission Organizations
- The Price of Natural Gas
- Environmental Regulations
- Renewable Portfolio Standards
- The Degree of Conservation
- Distributed Generation
- Future Generator Additions

Regional Transmission Organizations (RTO) are part of FERC's standard market design. Under an RTO, transmission owners (i.e., utilities) relinquish control or ownership of their transmission assets to the RTO. Within FERC standard market design, the RTO oversees a centralized, bid-based security constrained generation dispatch using locational marginal pricing (LMP) to manage transmission congestion and financial transmission rights (FTR) to

hedge transmission costs. The assumption is that under an RTO, OPPD sales volume will decrease. In the IRP model, the structure of transmission organizations is modeled indirectly in terms of increases or decreases to wholesale interchange sales volume which is adjusted with the equivalent forced outage rate.

Allowance prices are assigned to SO_2, NO_X, CO_2, and mercury; furthermore, with the "4P Legislation" market driver, the cost of natural gas is also increased due to price increases caused by fuel switching.

The degree of conservation, and distributed generation is modeled in terms of decreases to the peak load and energy forecast. The impact of future generator units in the region are modeled in the IRP in terms of unit retirements and assuming that no new coal units will be built.

End-state Scenarios

The issues team developed three end-state scenarios based on market dynamics in addition to the OPPD fuel budget scenario which was considered the baseline scenario.

- Mean Green Scenario
- Status Quo/Happy Days
- Bet the Farm (Expected)

The issues team expects that the "Bet the Farm" scenario is the most likely. The market dynamic drivers developed by the issues team for each scenario are shown in Table 14.

Table 14 – Wholesale Market Scenarios and Market Drivers

	SCENARIO			
MARKET DYNAMIC DRIVERS	**Fuel Budget (Baseline) Scenario**	**"Mean Green" Scenario**	**"Status Quo/ Happy Days" Scenario**	**"Bet the Farm" (Expected) Scenario**
RTO	No	Yes	No	Yes
Wholesale Market Price	Base Case	Slightly Higher – 10% increase	Base Case	Slightly Lower – 10% decrease
Equivalent Forced Outage Rate (EFOR)	NO – 7% NC – 7%	NO – 15% NC – 20%	NO – 7% NC – 7%	NO – 12% NC – 12%
Price of Natural Gas	Base Case (Relatively high in comparison to some forecasts)	Very High - $3.00/MMBTU increase over base case	Base Case (Relatively high in comparison to some forecasts)	Medium – $1.50/MMBTU decrease below benchmark
Environmental Regulations	Clear Skies Legislation – Bench mark w/ CO_2	4P Legislation (SO_2, NO_X, CO_2, & Mercury)	Clear Skies Legislation – Bench mark wo/ CO_2	Stringent 3P Legislation (SO_2, NO_X, & Mercury)
Emission Allowance Costs	SO_2=$90/ton NO_X=$675/ton CO_2=$5-23/ton Hg=$7500/lb	SO_2=Bench*1.2 NO_X=$675/ton CO_2=$10-46/ton Hg=$7500/lb	SO_2=$90/ton NO_X=$675/ton CO_2=$0/ton Hg=$7500/lb	SO_2=Bench*1.1 NO_X=$1000/ton CO_2=$5-23/ton Hg=$7500/lb
Emission Base Allowance	SO_2 – Current Allowance NO_X – Based on HDR MPC Rpt. CO_2 – Capped at 2000 Level Hg=731 lb/yr (70% reduction)	SO_2 – Current Allowance NO_X – Based on HDR MPC Rpt. CO_2 – Capped at 2000 Level Hg=731 lb/yr (70% reduction)	SO_2 – Current Allowance NO_X – Based on HDR MPC Rpt. CO_2 – Capped at 2000 Level Hg=731 lb/yr (70% reduction)	SO_2 – Current Allowance NO_X – Based on HDR MPC Rpt. CO_2 – Capped at 2000 Level Hg=731 lb/yr (70% reduction)
Renewable Portfolio Standards	No RPS	15% (2%/yr beginning in 2010, wind energy, includes existing renewables)	No RPS	5% (1%/yr beginning in 2010, wind energy, includes existing renewables)
The Degree of Conservation (Demand-side Mgt.)	No Change	High Conservation – 270 MW decrease in peak demand by 2023, LF for energy stays the same	No Change	Modest Conservation – 1/3 of "Mean Green" reductions
Distributed Generation	No Change	Increased DG - decrease in peak demand included in conservation reduction	No Change	No Change
Future Generator Additions	No Change	Old Units Retired after 70 years, No new coal units, Increase in CC units	No Change	No Change

The results from these scenarios are shown in Table 15 and also in Attachment 15.

Table 15 – Wholesale Market Scenario Results

Scenario	Generation Units in 20-year Plan	NPV 2007 M$'s	Change from Bench M$'s	Change from Bench
Base Case OPPD 15 Year Plan	Coal-fired unit in 2023	$10,027	-	-
"Mean Green" (Case B03-MG)	No Gas until 2022, 600 MW Wind	$9,460	($567)	(5.7%)
"Status Quo" (Case B03-HD)	Coal-fired unit in 2021	$8,170	($1,857)	(18.5%)
"Bet the Farm" (Case B03-BF)	Power uprate & all Gas until 2037, 200 MW Wind	$8,730	($1,297)	(12.9%)

10.2 Mean Green Scenario

The Mean Green scenario has increased costs for fossil fuel emissions, increased natural gas prices, an increased rate of growth in the carbon tax and a 15% renewable portfolio standard (RPS) as some key variations to the benchmark assumptions. Also, a lower load growth forecast is assumed in the scenario. OPPD customers' conservation of peak demand by 270 MW could come to fruition for the following reasons. Certainly, much higher rates for electricity driven by higher fuels and emission costs would lead to some level of conservation. Technological innovations may lead customers away from the electrical grid for a portion of their energy needs. Conservation could also occur by programs directed at consumers driven by either an OPPD business decision or governmental mandate. This scenario assumes that customers voluntarily reduce consumption without any incentives or rebates from an OPPD DSM program. An OPPD DSM team is currently evaluating the potential costs of any future DSM programs. The scenario does not allow coal-fired generation as a future resource. The next non-wind unit is the conversion of Cass County to combined cycle operation in 2022, this is an 8 year delay from the base case. All resource needs up until 2033 are met by natural-gas fired CT's and another combined cycle unit in 2028. In year 2033 a 600 MW share of nuclear generation is required. The Ft. Calhoun power uprate is not economical. Meeting the 15% RPS requires 600 MW of wind to be installed in out-state Nebraska locations. Wholesale market prices tend to follow natural gas costs. This scenario portrays a higher price of both these commodities. OPPD is a net seller in the wholesale market. Gains from selling into a higher wholesale market are offset by some extent by higher natural gas costs. A carbon tax which reaches $35/ton by 2032 and a $3/MMBtu adder to the natural gas forecast will tend to increase the NPV cost of the Mean Green scenario. Higher wholesale markets with

the added impact of conservation, will tend to lower the NPV of the Mean Green scenario and these changes carry the most impact as the Mean Green NPV is 5.7% lower than the base case.

10.3 Status Quo Scenario

The Status Quo scenario has no carbon tax implemented during the study years and is the only significant variation from the IRP bas case assumptions. By comparison, the base case assumes a $5/ton carbon tax beginning in 2012 increasing to $23/ton in 2032 and the Mean Green scenario assumes an increase in carbon tax to $35/ton by 2032. Zeroing out the carbon tax, and deriving a different optimized plan than the base case, provides a NPV reduction from the base case of 18.5%. The cost of a $1/ton carbon tax can be put in more meaningful scale, it adds around $1/MWh to the cost of coal generation. The Status Quo scenario does not assume any conservation. The absence of a carbon tax moves up the pulverized coal baseload option to 2021. This scenario demonstrates the large impact a carbon tax has on the optimum expansion plan and its NPV cost.

10.4 Bet the Farm Scenario

The Bet the Farm scenario is the scenario the evolving market issues team put forth as the most likely scenario. This scenario lowers the base natural gas forecast. It leaves the carbon tax at $5 to 23/ton which is the 2008 IRP base case assumption. It assumes some conservation in the load forecast over the base case. It assumes a 5% renewable portfolio standard (RPS). The 5% RPS leads to 200 MW of wind farms in out-state Nebraska. The scenario also assumes a 10% decrease in the wholesale market price forecast. The NPV of the resulting Bet the Farm plan is 12.9% lower than the benchmark case. Conservation delays Cass County conversion until 2018. Similar to the Mean Green scenario, only natural gas fired resources are added until late in the planning period. The next coal unit is not needed until 2037. The Ft. Calhoun power uprate is economical and included in the plan. The lower rate of load growth with the delay of the Cass County conversion and the delay of the next coal unit until 2038 lowers the Bet the Farm scenario NPV cost.

Additional details regarding the expansion plans for the evolving market scenarios are shown in Attachment 18.

Attachments

Attachment 1

Load and Generation Capability (Summer)

Summer Conditions (May 1 to October 31)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1. Seasonal System Demand																
Base Peak (June 2008 LF-50/50)	2349	2486	2602	2669	2694	2725	2762	2799	2834	2872	2907	2944	2981	3017	3053	3086
Less Curtailable Load	-56.1	-56	-56	-56	-56	-56	-56	-56	-56	-56	-56	-56	-56	-56	-56	-56
Total	2293	2430	2545	2613	2638	2669	2706	2743	2778	2815	2851	2888	2925	2961	2997	3030
2. Annual System Demand	2293	2430	2545	2613	2638	2669	2706	2743	2778	2815	2851	2888	2925	2961	2997	3030
3. Firm Purchases - WAPA	82	82	82	**81**	81	81	81	81	81	81	81	81	81	81	81	81
4. Firm Sales																
Wholesale Towns (a)	11	12	12	12	12	12	13	13	13	13	13	13	14	14	14	14
Total	11	12	12	12	12	12	13	13	13	13	13	13	14	14	14	14
5. Seasonal Adj. Net Demand (1-3+4)	2222.0	2361	2476	2545	2570	2600	2637	2675	2710	2747	2783	2820	2858	2894	2929	2963
6. Adjusted Net Demand (2-3+4)	2222.0	2361	2476	2545	2570	2600	2637	2675	2710	2747	2783	2820	2858	2894	2929	2963
7. Net Generating Capability																
Fort Calhoun	482.0	**484**	484	484	484	**559**	559	559	559	559	559	559	559	559	559	559
Nebraska City #1	646.0	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646
Nebraska City #2	0	**663**	663	663	663	663	663	663	663	663	663	663	663	663	663	663
North Omaha	662.8	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663
Sarpy County	314.3	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Jones Street	118.4	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118
Cass County	320.0	320	320	320	320	320	**530**	530	530	530	530	530	530	**690**	690	690
Elk City Landfill Gas	5.3	**6**	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Future Baseload Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**330**
Future Peaking Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2548.8	3215	3215	3215	3215	3290	3500	3500	3500	3500	3500	3500	3500	3660	3660	3990
8. Participation Purchases																
Tecumseh (leased)	6.6	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Wind Energy	2.2	7	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Unspecified Peaking Purchase	0	0	0	**55**	**85**	0	0	0	0	0	0	**20**	**65**	0	0	0
Total	8.8	14	17	72	102	17	17	17	17	17	17	37	82	17	17	17
9. Participation Sales																
Nebraska City #2 Participants	0	**331.5**	332	332	332	332	332	332	332	332	332	332	332	332	332	332
WAPA	25	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
City of Gardner Kansas	**0**	4	5	10	15	0	0	0	0	0	0	0	0	0	0	0
Total	25	386	387	392	397	332	332	332	332	332	332	332	332	332	332	332
10. Accredited Capability (7+8-9)	2533	2843	2845	2895	2920	2975	3185	3185	3185	3185	3185	3205	3250	3345	3345	3675
11. Net Reserve Capacity Obligation (6 X 13.64%)	303	322	338	347	350	355	360	365	370	375	380	385	390	395	400	404
12. Total Firm Capacity Obligation (5+11)	2525	2683	2814	2892	2920	2955	2997	3040	3080	3122	3163	3205	3248	3288	3329	3367
13. Surplus or Deficit Capacity (10-12)	8	160	31	3	0	20	187	145	105	62	22	0	2	57	16	308
14. Reserve Margin (10/5)	14.0%	20.4%	14.9%	13.8%	13.6%	14.4%	20.7%	19.1%	17.5%	15.9%	14.4%	13.6%	13.7%	15.6%	14.2%	24.0%

Summer Capability Changes:

Elk City Landfill
0.76 MW - Jan 2009

Ft. Calhoun
75 MW - 2013 (HP Rotor)

Nebraska City #2
663 MW - May 2009
(Sell 331.5 MW Long-Term)

Cass County #3: CC Conversion
210 MW - 2014

Cass County #4: CT
160 MW - 2021

Outstate Wind Energy
25 MW Nameplate -2009
13 MW Nameplate -2010

(a) Consists of the projected demands of the Nebraska municipal utilities of Syracuse, Greenwood, Elk Creek, and Tecumseh. All are served at wholesale by the District.

Attachment 2

Load and Generation Capability (Winter)

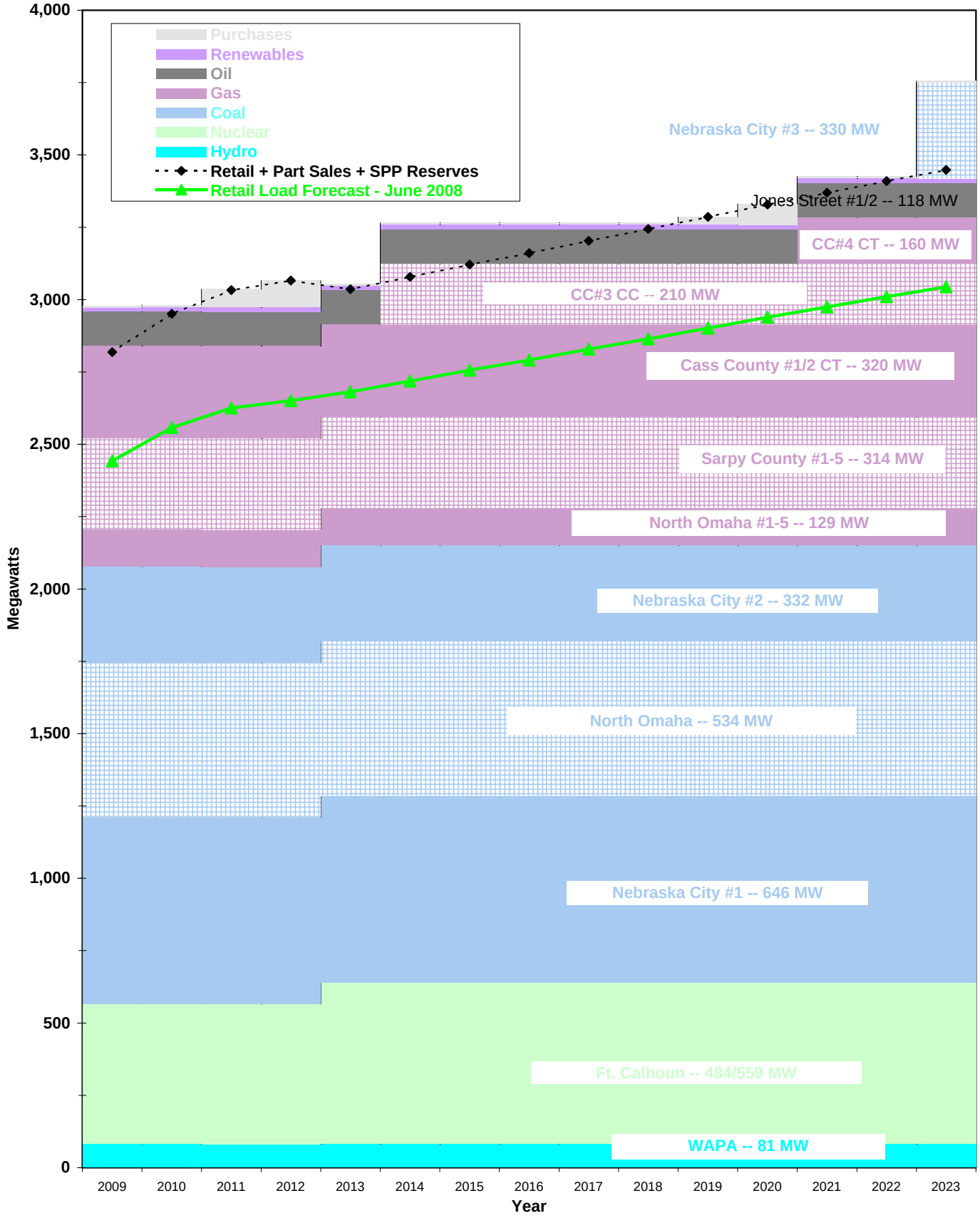
Winter Conditions (November 1 to April 30)

	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
1. Seasonal System Demand															
Base Peak (June 2008 LF-50/50)	1575	1568	1863	1938	1929	1957	1939	2060	2028	2095	2098	2128	2114	2216	2241
Add New Customer Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1575	1568	1863	1938	1929	1957	1939	2060	2028	2095	2098	2128	2114	2216	2242
2. Annual System Demand	2222	2293	2430	2545	2613	2638	2669	2706	2743	2778	2815	2851	2888	2925	2961
3. Firm Purchases - WAPA	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
4. Firm Sales -															
Wholesale Towns (a)	8	9	10	10	10	10	10	10	10	10	10	10	10	11	11
Total	8	9	10	10	10	10	10	10	10	10	10	10	10	11	11
5. Seasonal Adjusted Net Demand (1-3+4)	1541	1534	1830	1906	1897	1925	1907	2028	1996	2063	2066	2097	2082	2184	2210
6. Adjusted Net Demand (2-3+4)	2188	2259	2398	2513	2581	2606	2637	2674	2711	2746	2784	2819	2856	2894	2930
7. Net Generating Capability															
Fort Calhoun	509	509	509	509	509	509	**588**	588	588	588	588	588	588	588	588
Nebraska City #1	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653
Nebraska City #2	0	0	**663**	663	663	663	663	663	663	663	663	663	663	663	663
North Omaha	534	534	534	534	534	534	534	534	534	534	534	534	534	534	534
Sarpy County	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353
Jones Street	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129
Cass County	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Elk City Landfill Gas	**5**	5	**6**	6	6	6	6	6	6	6	6	6	6	6	6
Future Baseload Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Peaking Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2184	2184	2847	2847	2847	2847	2926	2926	2926	2926	2926	2926	2926	2926	2926
8. Participation Purchases															
Tecumseh (leased)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Wind Energy	2	2	7	10	10	10	10	10	10	10	10	10	10	10	10
Total	9	9	14	17	17	17	17	17	17	17	17	17	17	17	17
9. Participation Sales -															
Nebraska City #2 Participants	0	0	**332**	332	332	332	332	332	332	332	332	332	332	332	332
WAPA	0	25	50	50	50	50	0	0	0	0	0	0	0	0	0
City of Gardner Kansas	0	0	4	5	10	15	0	0	0	0	0	0	0	0	0
Total	0	25	386	387	392	397	332	332	332	332	332	332	332	333	334
10. Accredited Capability (7 + 8 - 9)	2192	2167	2475	2477	2472	2467	2611	2611	2611	2611	2611	2611	2611	2610	2609
11. Net Reserve Capacity Obligation (6 x 13.64%)	328	339	360	377	387	391	396	401	407	412	418	423	428	434	439
12. Total Firm Capacity Obligation (5 + 11)	1869	1873	2190	2283	2284	2316	2303	2429	2403	2475	2484	2520	2510	2618	2649
13. Surplus or Deficit Capacity (10 - 12)	323	294	285	194	189	151	309	183	208	137	127	92	101	-8	-40
14. Reserve Margin (10 / 5)	42.3%	41.3%	35.2%	30.0%	30.3%	28.2%	37.0%	28.8%	30.8%	26.6%	26.4%	24.6%	25.4%	19.5%	18.1%

(a) Consists of the projected demands of the Nebraska municipal utilities of Syracuse, Greenwood, Elk Creek, and Tecumseh. All are served at wholesale by the District.

Attachment 3

Load and Capability



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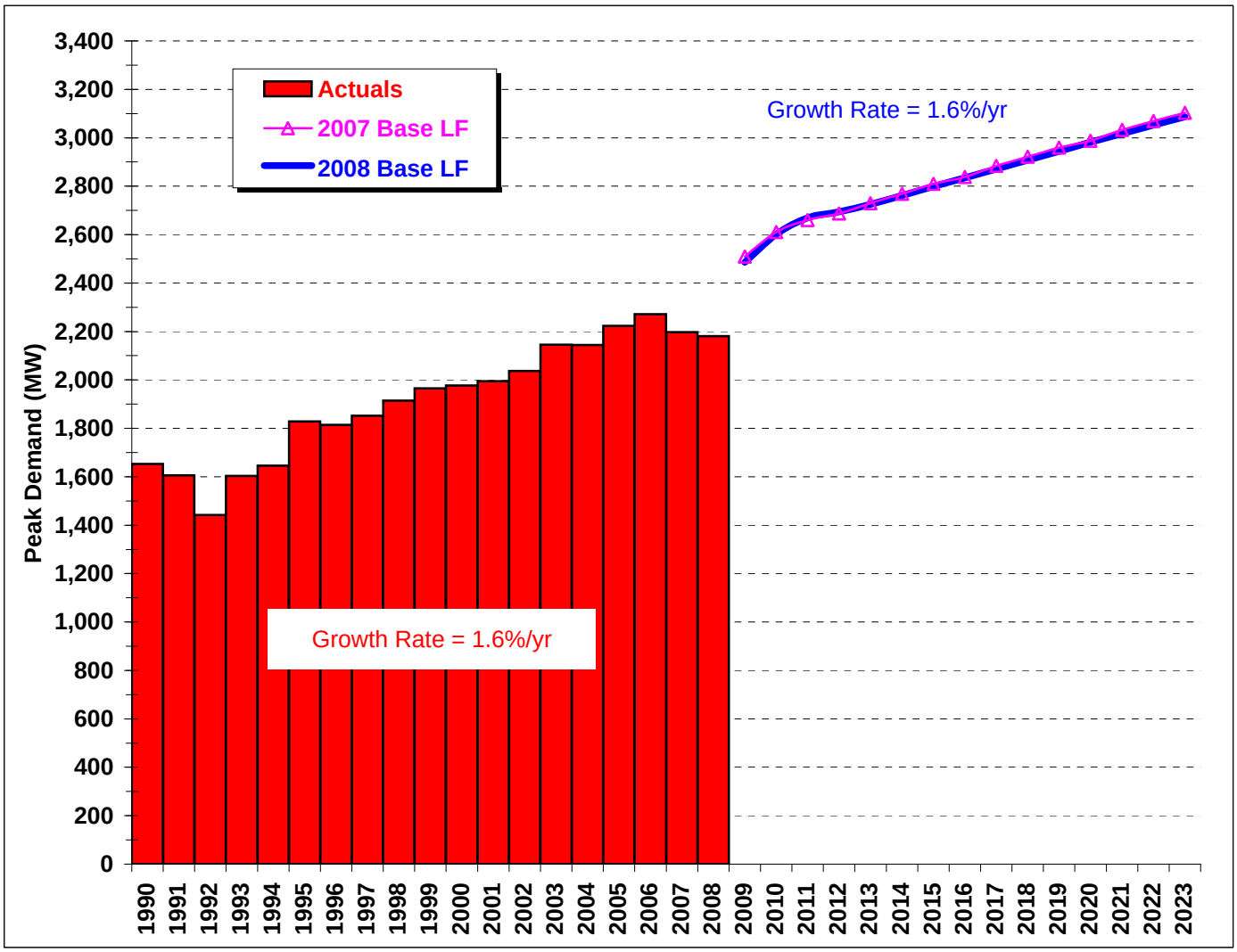
Attachment 4

Annual System Peak Demand Forecast

June 2008 Forecast



Year	Actual Peak MW	Date
1990	1,652.3	Aug-27
1991	1,605.9	Aug-14
1992	1,442.0	Jul-08
1993	1,603.1	Aug-17
1994	1,645.9	Aug-25
1995	1,828.0	Jul-12
1996	1,813.9	Jul-18
1997	1,851.8	Jul-25
1998	1,914.0	Jul-20
1999	1,965.6	Jul-28
2000	1,976.9	Aug-30
2001	1,994.1	Aug-01
2002	2,037.4	Jul-19
2003	2,144.8	Aug-25
2004	2,143.8	Jul-20
2005	2,223.3	Jul-22
2006	2,271.9	Jul-19
2007	2,197.4	Jul-18
2008	2,181.1	Jul-15
Growth 90-08	1.6%	

Year	Forecast w/o curtailments: 2008 Base LF	Growth	2007 Base LF	Change
2009	2,486	305	2,509	-23
2010	2,602	115	2,610	-9
2011	2,669	68	2,660	10
2012	2,694	25	2,687	7
2013	2,725	31	2,730	-5
2014	2,762	37	2,769	-7
2015	2,799	37	2,809	-10
2016	2,834	35	2,838	-4
2017	2,872	37	2,884	-13
2018	2,907	36	2,922	-15
2019	2,944	37	2,959	-16
2020	2,981	38	2,987	-6
2021	3,017	36	3,033	-16
2022	3,053	36	3,069	-16
2023	3,086	34	3,103	-17
Nominal Growth Rate:	1.6%		1.5%	
Average Growth Rate:	43	MW/yr	42	

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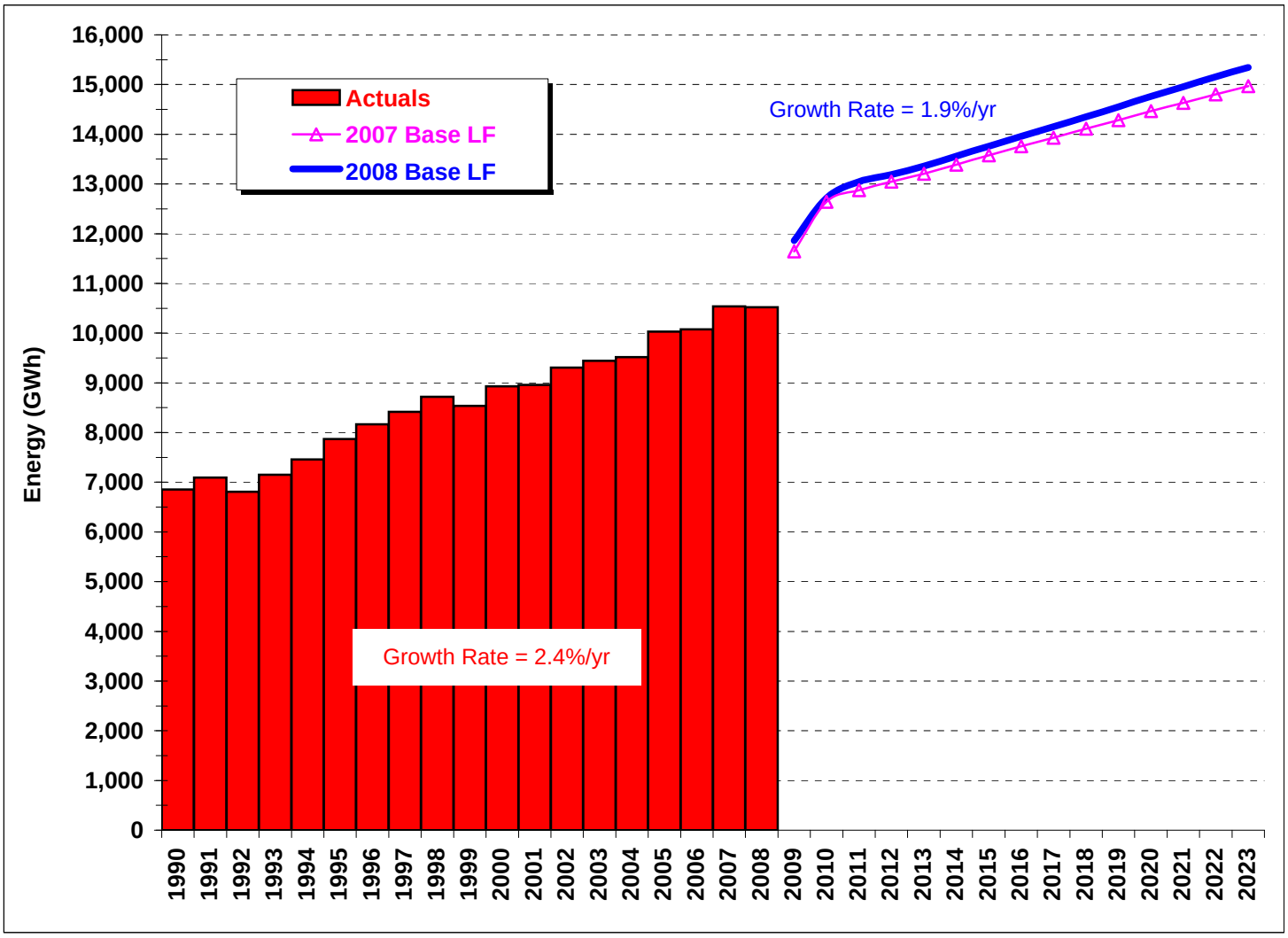
Attachment 5

Annual Net System Requirements Forecast

June 2008 Forecast



Year		Actual	Load Factor
1990		6,856	47.4%
1991		7,091	50.4%
1992		6,809	53.8%
1993		7,149	50.9%
1994		7,458	51.7%
1995		7,867	49.1%
1996		8,164	51.2%
1997		8,417	51.9%
1998		8,718	52.0%
1999		8,535	49.6%
2000		8,928	51.4%
2001		8,959	51.3%
2002		9,306	52.1%
2003		9,443	50.3%
2004		9,519	50.5%
2005		10,032	51.5%
2006		10,073	50.6%
2007		10,536	54.7%
2008	est	10,521	55.1%
Growth 89-08		2.4%	

	Forecast				
Year	2008 Base LF	LF	Growth	2007 Base LF	Change
2009	11,860	54.5%	1,339	11,641	219
2010	12,715	55.8%	854	12,641	73
2011	13,045	55.8%	330	12,875	170
2012	13,191	55.7%	146	13,044	146
2013	13,359	56.0%	168	13,206	153
2014	13,558	56.0%	200	13,387	171
2015	13,760	56.1%	202	13,578	182
2016	13,957	56.1%	197	13,757	200
2017	14,153	56.3%	197	13,932	222
2018	14,349	56.3%	196	14,110	239
2019	14,551	56.4%	201	14,286	264
2020	14,764	56.4%	213	14,464	300
2021	14,956	56.6%	193	14,633	323
2022	15,155	56.7%	199	14,805	350
2023	15,345	56.8%	190	14,967	378
Growth Rate:	1.9%			1.8%	
Average Growth Rate:	249	GWh/yr		238	

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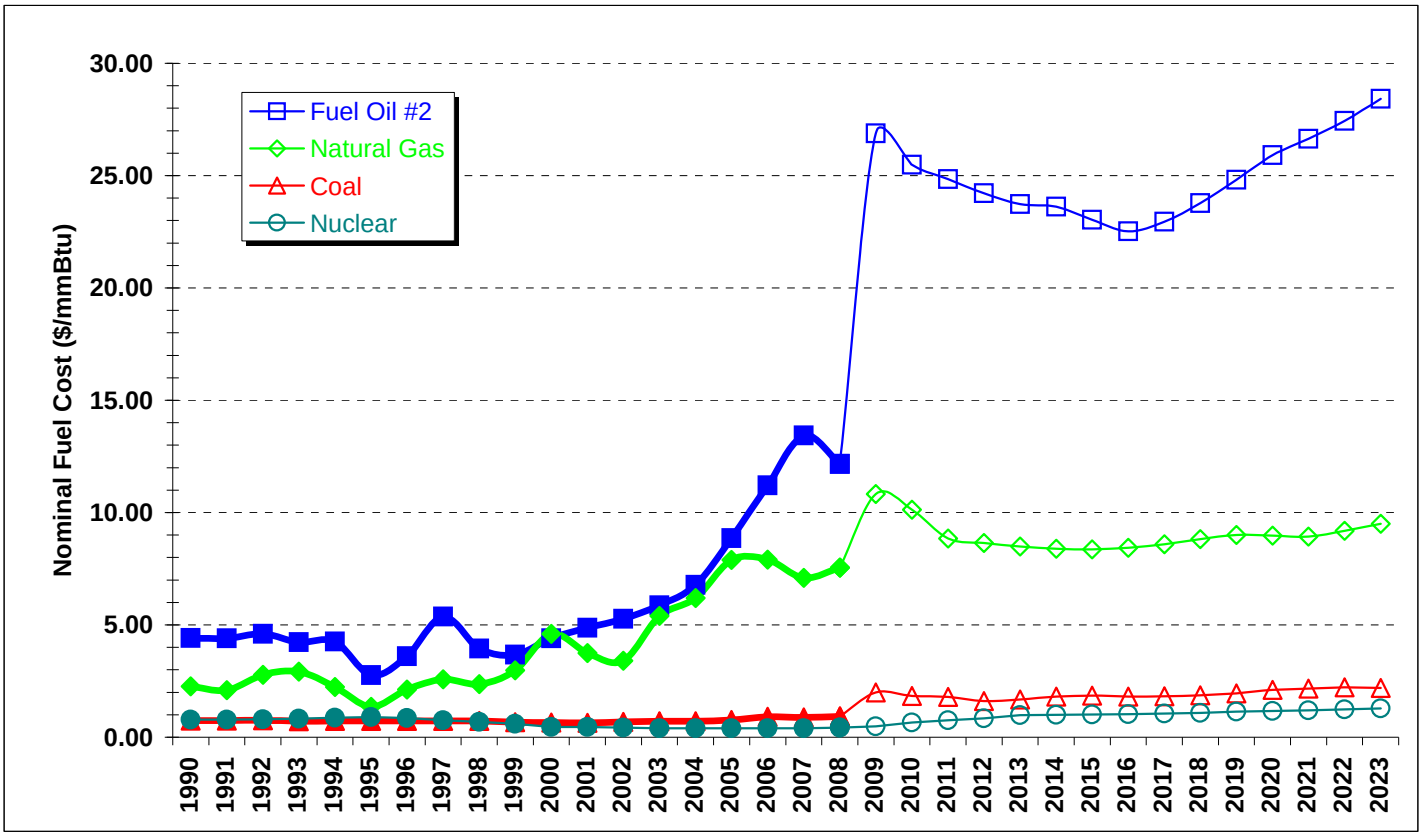
Attachment 6

Fuel Forecast

Nominal $/MMBtu



		Actuals			
Year		Coal	Gas	Oil	Nuclear
1990		0.74	2.27	4.41	0.79
1991		0.75	2.09	4.40	0.78
1992		0.76	2.78	4.61	0.80
1993		0.71	2.92	4.24	0.83
1994		0.72	2.24	4.26	0.87
1995		0.72	1.35	2.77	0.89
1996		0.72	2.13	3.61	0.86
1997		0.73	2.58	5.37	0.76
1998		0.73	2.37	3.94	0.69
1999		0.66	2.98	3.67	0.60
2000		0.66	4.60	4.40	0.46
2001		0.64	3.75	4.87	0.45
2002		0.68	3.41	5.27	0.43
2003		0.71	5.40	5.87	0.40
2004		0.72	6.20	6.78	0.40
2005		0.77	7.89	8.86	0.39
2006		0.91	7.91	11.21	0.40
2007		0.89	7.09	13.43	0.41
2008	est	0.92	7.55	12.17	0.43

	Forecasts			
Year	Coal*	Gas**	Oil**	Nuclear^
2009	2.00	10.83	26.88	0.49
2010	1.84	10.13	25.48	0.65
2011	1.80	8.85	24.84	0.76
2012	1.61	8.65	24.22	0.84
2013	1.67	8.50	23.73	0.98
2014	1.80	8.39	23.62	1.00
2015	1.85	8.37	23.03	1.01
2016	1.81	8.43	22.52	1.02
2017	1.82	8.60	22.95	1.06
2018	1.87	8.81	23.78	1.09
2019	1.96	9.01	24.82	1.14
2020	2.10	8.97	25.91	1.17
2021	2.16	8.93	26.64	1.20
2022	2.23	9.18	27.43	1.24
2023	2.19	9.50	28.42	1.28
Nominal Growth Rate:	0.67%	-0.92%	0.40%	7.17%
Real Growth Rate:	-1.21%	-2.77%	-1.5%	5.17%

* OPPD Bid Analysis

** L.E. Peabody & Associates

^ Uncontracted future uranium, conversion, enrichment and fabrication costs are obtained from Energy Resources International, Inc.

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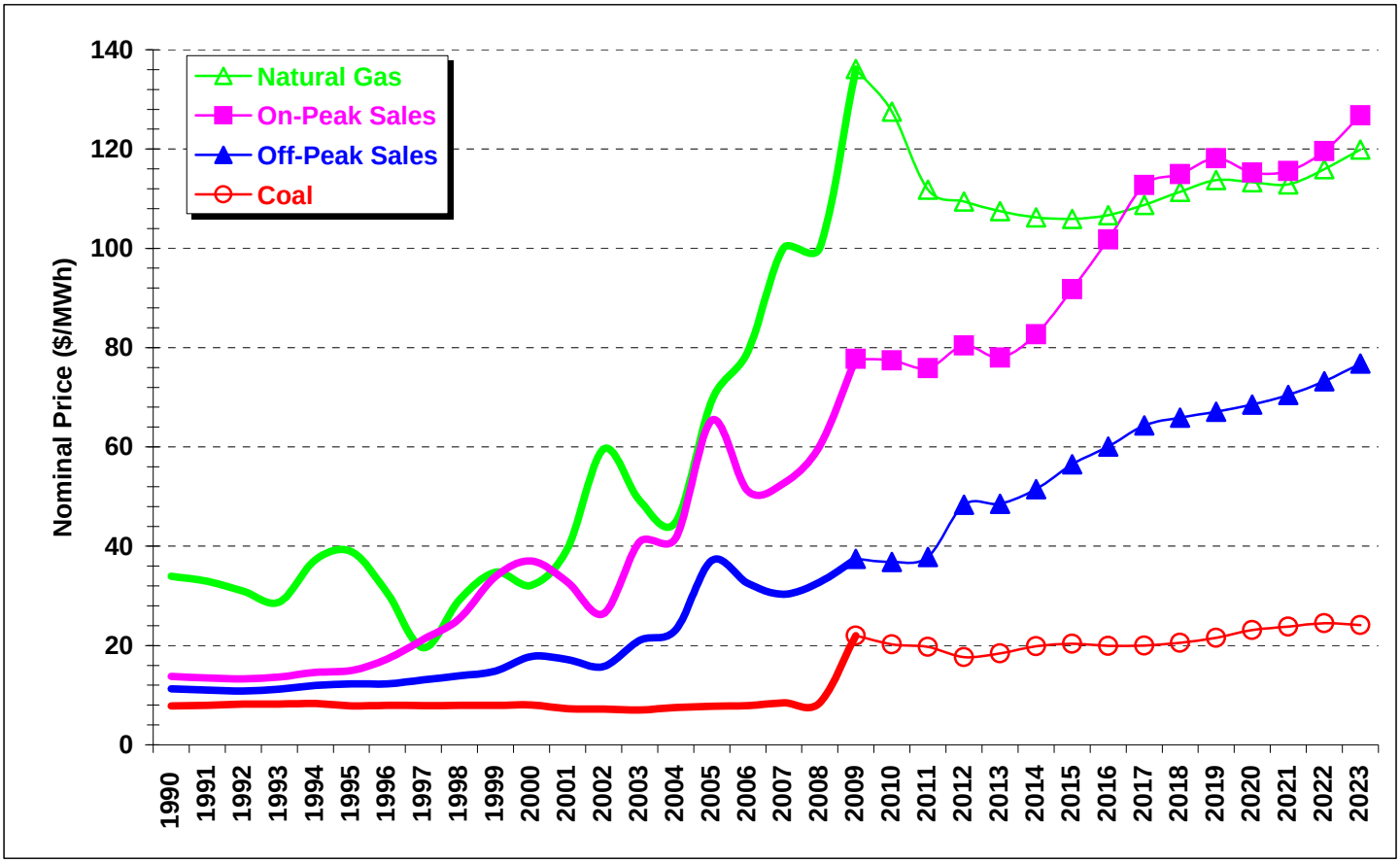
Attachment 7A

Annual Wholesale Market Forecast

Nominal $/MWh



		Actuals			
Year		Gas	On-Peak	Off-Peak	Coal
1990		33.9	13.8	11.3	7.8
1991		33.0	13.5	11.0	8.0
1992		30.9	13.3	10.8	8.2
1993		28.8	13.7	11.2	8.2
1994		37.3	14.6	11.9	8.4
1995		38.9	15.0	12.3	7.8
1996		30.6	17.3	12.3	8.0
1997		19.6	21.3	13.1	7.9
1998		29.2	25.5	13.9	8.0
1999		34.8	33.9	14.8	8.0
2000		32.1	37.0	17.8	8.0
2001		39.6	32.8	17.2	7.3
2002		59.6	26.5	15.8	7.2
2003		49.2	40.9	21.0	7.0
2004		44.9	41.7	23.2	7.5
2005		69.4	65.4	37.1	7.8
2006		79.3	51.1	32.5	7.9
2007		100.1	52.7	30.3	8.5
2008	est	100.1	60.2	32.8	8.5

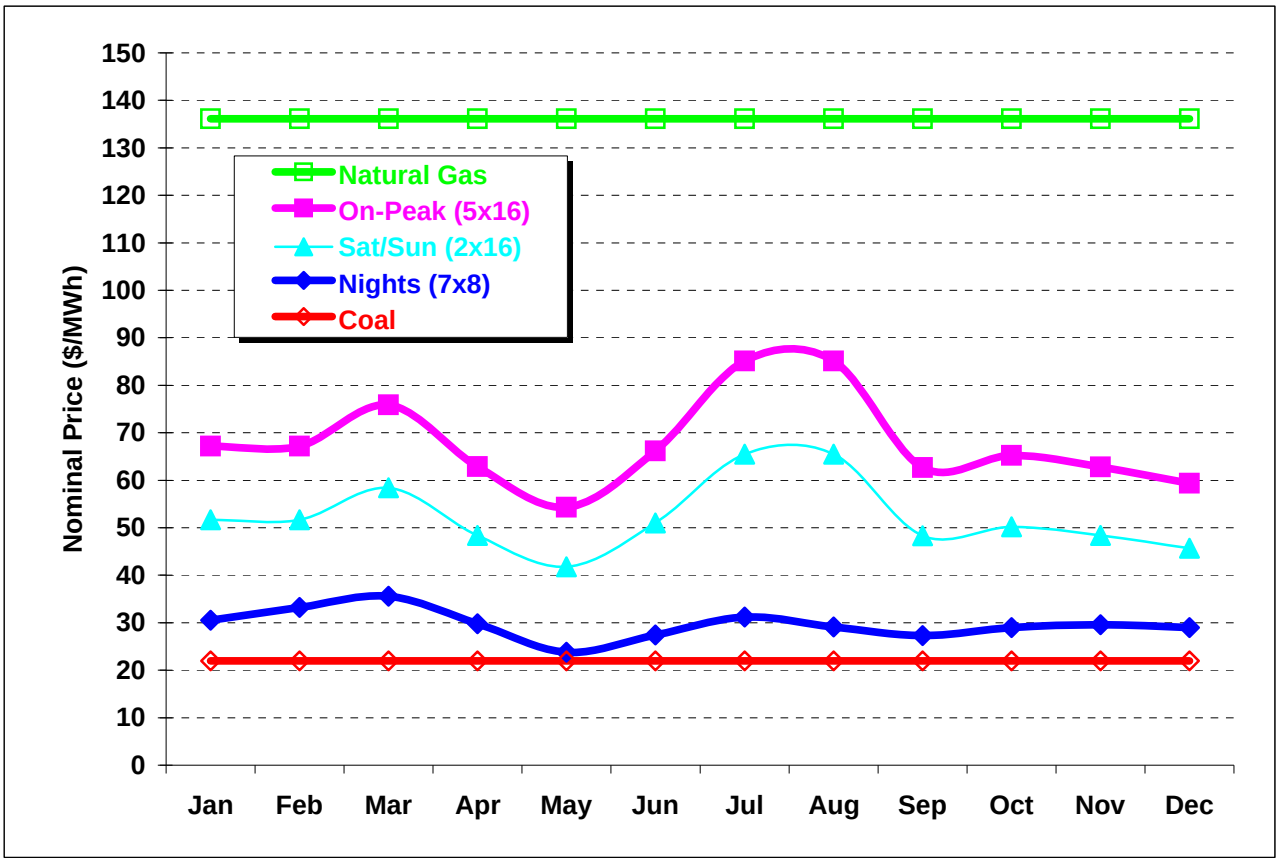
	Forecasts			
Year	Gas	On-Peak*	Off-Peak*	Coal
2009	136.1	77.8	37.4	22.0
2010	127.5	77.4	36.9	20.2
2011	111.8	75.9	37.8	19.8
2012	109.4	80.4	48.4	17.7
2013	107.5	78.0	48.5	18.4
2014	106.2	82.7	51.5	19.8
2015	105.9	91.8	56.5	20.3
2016	106.7	101.8	60.1	19.9
2017	108.7	112.7	64.3	20.0
2018	111.4	114.9	65.9	20.5
2019	113.8	118.2	67.1	21.5
2020	113.3	115.3	68.6	23.1
2021	112.9	115.6	70.5	23.8
2022	115.9	119.6	73.3	24.5
2023	119.9	126.8	76.8	24.1
Nominal Growth Rate:	-0.90%	3.55%	5.27%	0.67%
Real Growth Rate:	-2.75%	1.62%	3.30%	-1.21%

* Source: Global Energy Decisions

Attachment 7B

Monthly Wholesale Market Forecast

Market Forecast for 2009 ($/MWh)

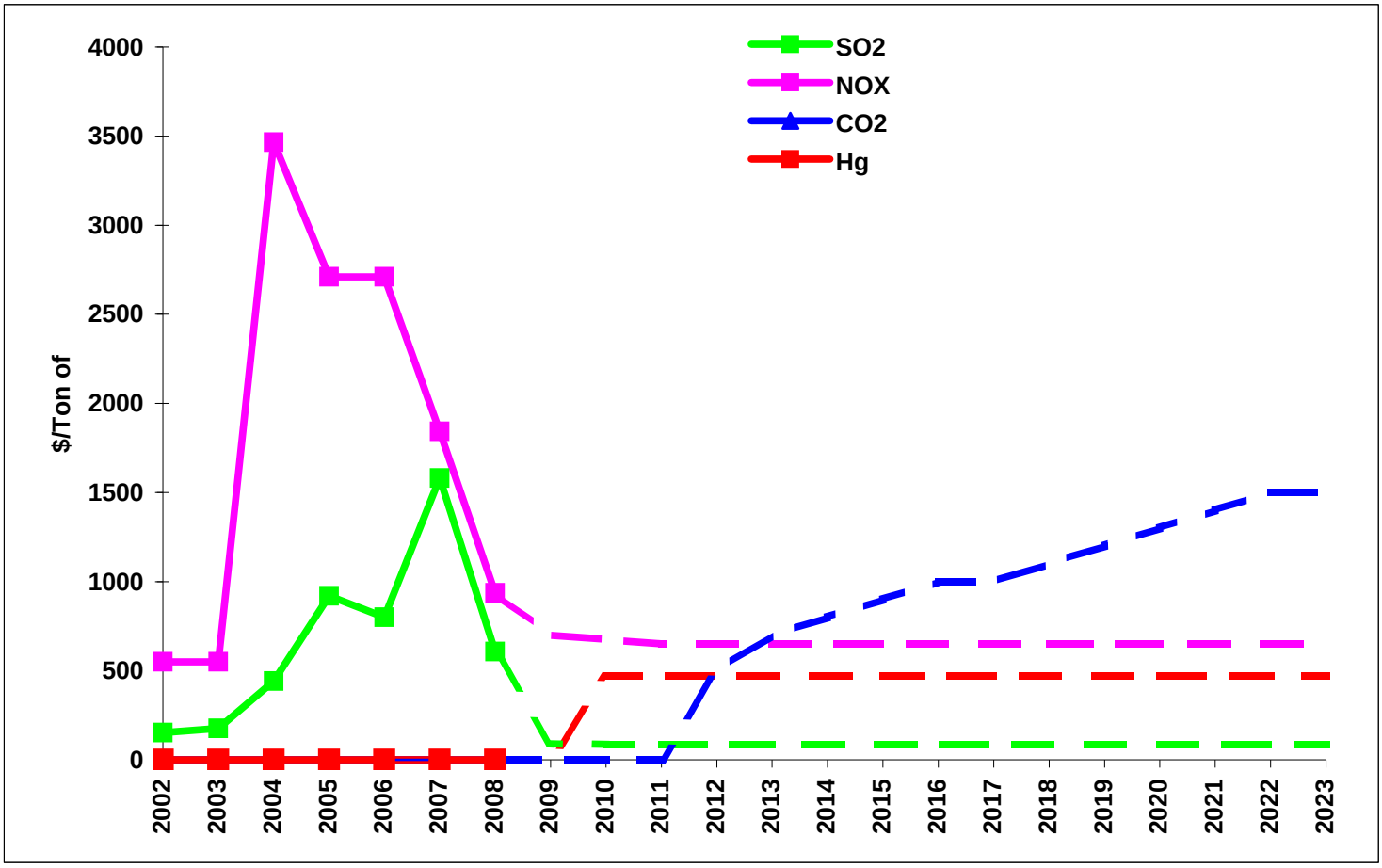


	Forecast				
Month	Gas	On-Peak	Sat/Sun	Nights	Coal
Jan	136.1	67.2	51.7	30.5	22.0
Feb	136.1	67.2	51.7	33.2	22.0
Mar	136.1	75.9	58.4	35.6	22.0
Apr	136.1	62.9	48.4	29.8	22.0
May	136.1	54.3	41.8	23.8	22.0
Jun	136.1	66.2	51.0	27.4	22.0
Jul	136.1	85.1	65.5	31.2	22.0
Aug	136.1	85.1	65.5	29.1	22.0
Sep	136.1	62.7	48.3	27.3	22.0
Oct	136.1	65.2	50.2	29.0	22.0
Nov	136.1	62.8	48.4	29.6	22.0
Dec	136.1	59.4	45.7	29.0	22.0
Average	136.1	48.9	37.7	21.4	22.0

Attachment 8

Environmental Externality/Allowance Trading Forecast

Nominal $/Ton of Effluent for SO_2 and NO_X ($/100-Ton for CO_2, $/ounce for Hg)



	Previous Forecasts			
Year	SO_2	NO_X	CO_2	Mercury
2002	152	550	0	0
2003	176	550	0	0
2004	442	3466	0	0
2005	919	2711	0	0
2006	800	2711	0	0
2007	1580	1842	0	0
2008	607	937	0	0

	Future Forecasts			
Year	SO_2	NO_X	CO_2	Mercury
2009	90	700	0	0
2010	87	675	0	469
2011	87	650	0	469
2012	87	650	500	469
2013	87	650	700	469
2014	87	650	800	469
2015	87	650	900	469
2016	87	650	1000	469
2017	87	650	1000	469
2018	87	650	1100	469
2019	87	650	1200	469
2020	87	650	1300	469
2021	87	650	1400	469
2022	87	650	1500	469
2023	87	650	1500	469

(1) SO_2 Allowance Cost is based on the currently active Acid Rain Program.

(2) NO_X Allowance Cost before 2004 is cost to install low nox burners, 2004 and after is based on the currently active NO_X SIP Market in Eastern US.

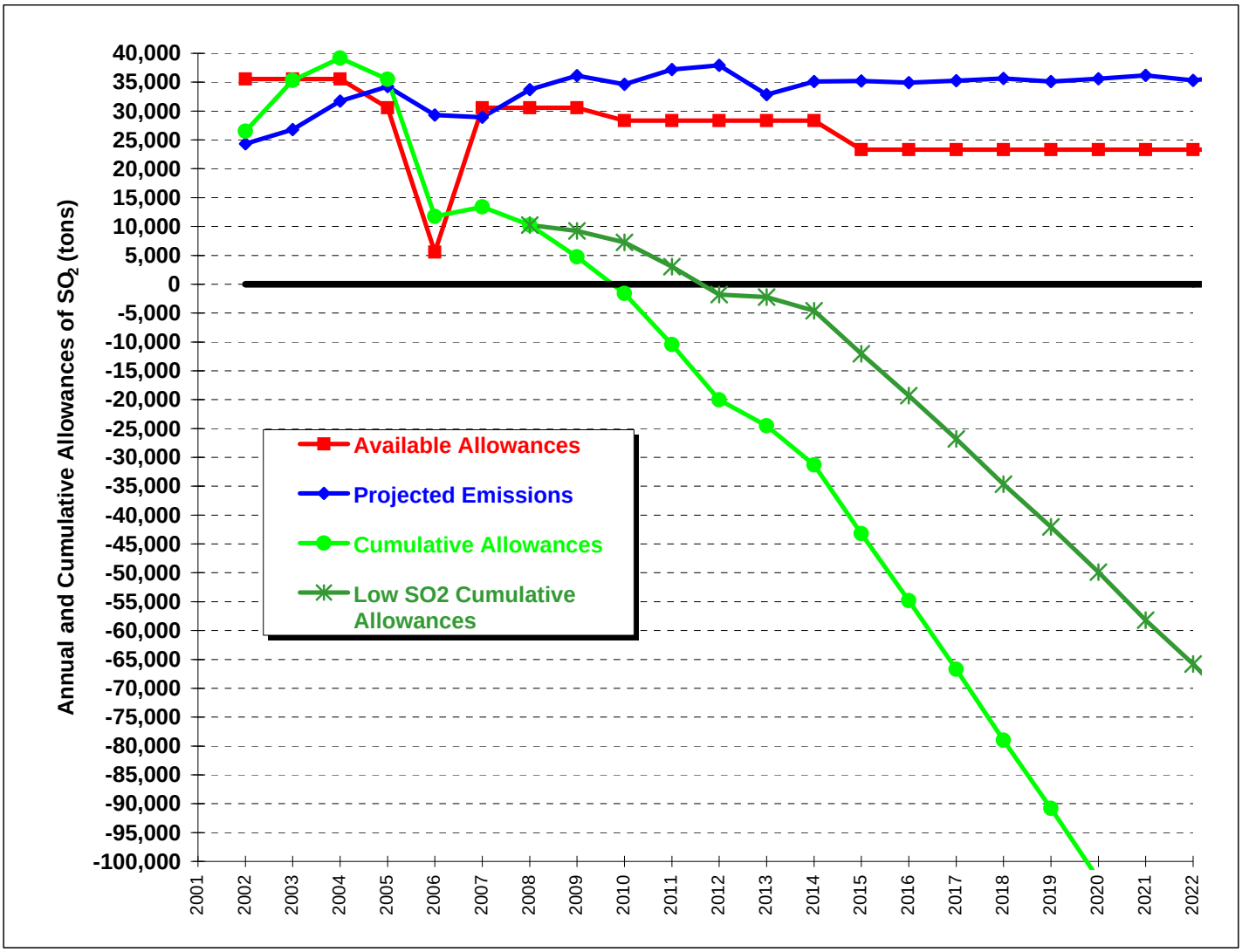
(3) CO_2 Allowance Cost is estimate of a legislated CO_2 Cap and Trade Program.

(4) Mercury Allowance Cost is estimated market price

Attachment 9

SO_2 Emissions & Acid Rain Program Allowances

(Tons SO_2)



Notes: (1) Cumulative Allowances are projected surplus/(deficit) inventory of allowances at end of each year.

(2) Sold 25,000 allowances in 2006 and purchased 5,000 allowances per year 2010-2014.

(3) Projected emissions based on 2008 fuel budget data base (FB082205) and 2007 YTD estimate.

(4) Based on SO2 emission rates of [*] 0.8 lb/mmBtu for North Omaha 1-5 and Nebraska City #1 and 0.1 lb/mmBtu for Nebraska City #2. [* SO2 emissions varies by mine providing OPPD coal]

(5) Low SO2 Cumulative Allowances Case assumes rates of 0.7 lb/mmBtu [*] for North Omaha 1-5 and Nebraska City #1, 2009 and beyond.

Tons of SO_2

Year		Projected Emissions	Available Allowances	Cumulative (Deficit)	Year	Projected Emissions	Available Allowances	Cumulative (Deficit)
2002	act	24,330	35,573	26,515	2013	32,863	28,334	(20,021)
2003	act	26,783	35,573	35,305	2014	35,093	28,334	(24,550)
2004	act	31,718	35,573	39,160	2015	35,222	23,334	(31,309)
2005	act	34,256	30,573	35,477	2016	34,936	23,334	(43,197)
2006	act	29,308	5,573	11,742	2017	35,241	23,334	(54,799)
2007	act	28,910	30,573	13,405	2018	35,651	23,334	(66,706)
2008	est	33,720	30,573	10,258	2019	35,110	23,334	(79,023)
2009		36,119	30,573	4,712	2020	35,600	23,334	(90,799)
2010		34,631	28,334	(1,585)	2021	36,196	23,334	(103,065)
2011		37,181	28,334	(10,432)	2022	35,322	23,334	(115,927)
2012		37,923	28,334	(20,021)	2023	36,293	23,334	(127,915)

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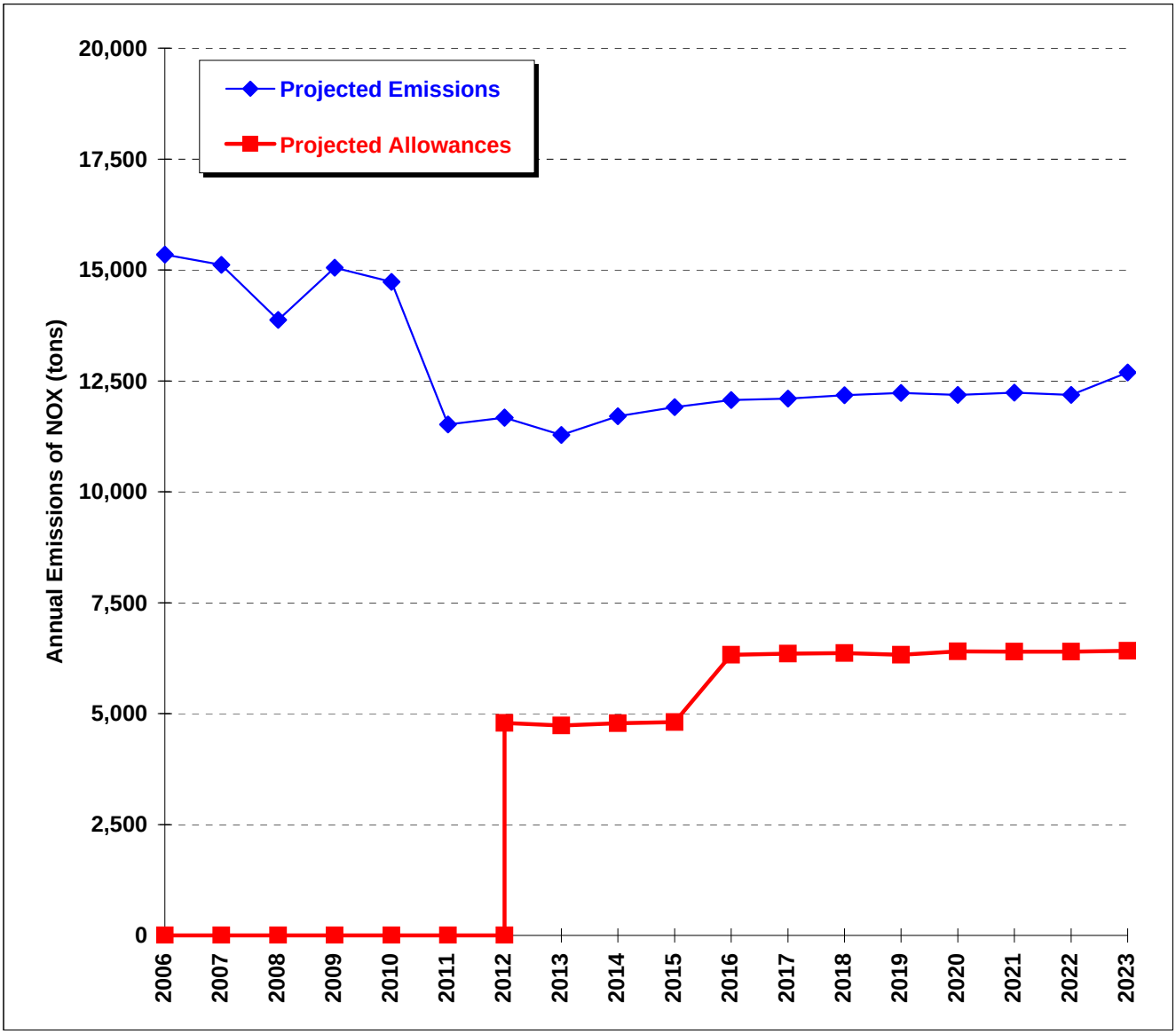
Attachment 10

NO_X Emissions Under a Multi-Pollutant Standard

(Tons NO_X)



Notes: (1) Projected emissions based on 2008 IRP PROVIEW.

(2) Based on NO_X emission rates of 0.313 lb/MMBtu for North Omaha 1-3, 0.331 for NO#4, 0.298 for NO#5, 0.394 for Nebraska City #1, and 0.150 for Nebraska City #2.

(3) Projected allowances based on HDR Analysis of MPC legislation. Dependent on legislative approval. 2008 IRP analysis assumes 2012 implementation.

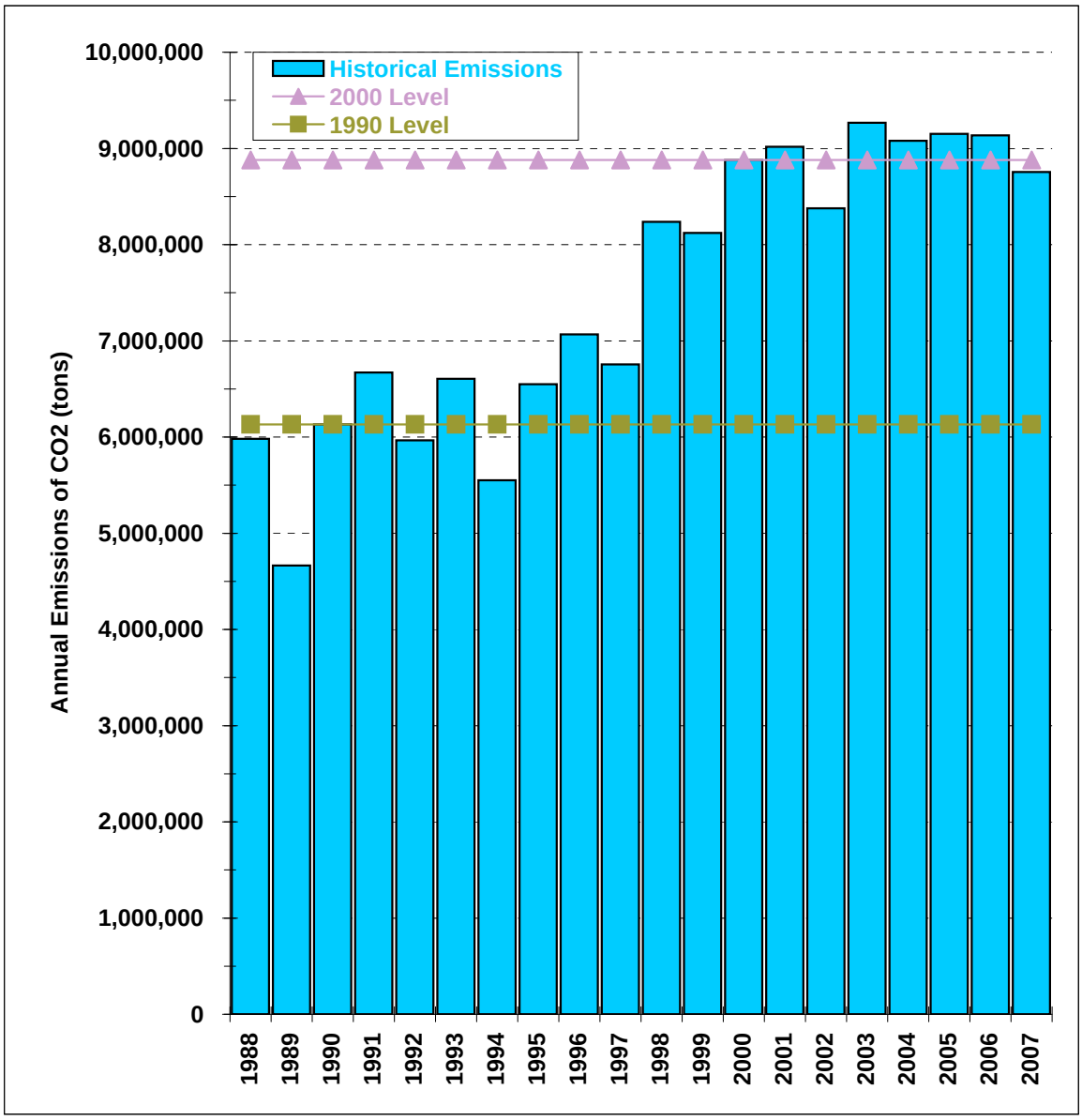
* Actual

Tons of NO_X

Year		Projected Emissions	Projected Allowances	Surplus (Deficit)	Year	Projected Emissions	Projected Allowances	Surplus (Deficit)
2006	*	15,685			2015	11,906	4,810	(6,860)
2007	*	15,560			2016	12,068	6,323	(5,745)
2008	*	15,560			2017	12,102	6,348	(5,754)
2009		15,053			2018	12,175	6,364	(5,811)
2010		14,733			2019	12,225	6,327	(5,898)
2011		11,515			2020	12,185	6,401	(5,784)
2012		11,670			2021	12,233	6,397	(5,836)
2013		11,280	4,733	(6,547)	2022	12,180	6,396	(5,784)
2014		11,703	4,785	(6,918)	2023	12,690	6,417	(6,273)

Attachment 11

Historical CO_2 Emissions



Note: Emissions are calculated from Fuel Division Production Statistics

Year	Historical CO_2 Emissions (Tons)	
1988	5,979,842	
1989	4,665,647	
1990	6,129,988	1990 Level
1991	6,670,550	
1992	5,964,924	
1993	6,605,541	
1994	5,550,192	
1995	6,549,709	
1996	7,066,231	
1997	6,755,781	

Year	Historical CO_2 Emissions (Tons)	
1998	6,755,781	
1999	8,238,388	
2000	8,880,552	2000 LEVEL
2001	9,016,518	
2002	8,376,778	
2003	9,266,980	
2004	9,078,927	
2005	9,150,680	
2006	9,135,762	
2007	8,754,603	

CO_2 Emission Rates (lb/mmBtu):	
Coal:	213
Oil:	165
Natural Gas:	126
Propane:	137

Attachment 12

Supply-Side Options

2009$

Resource Option	Size MW	Primary Fuel	Capacity Factor	Installed * Capital Cost ($/kW)	Operating Cost ** (cent/kWh)	Levelized Busbar Cost (cent/kWh)
Baseload						
Landfill Gas to Energy - Incr.	3	Methane	95%	1,625	1.5	2.7
LFGTE Greenfield	6	Methane	95%	1,815	2.5	3.8
Coal, Wood Retrofit	100	Wood	85%	2,906	1.6	4.0
Landfill Gas to Energy (LFGTE)	6	Methane	85%	1,815	2.7	4.2
Fluidized Bed	200	Coal	85%	2,211	5.5	7.3
Nebraska City #3	660	Coal	85%	3,029	5.0	7.4
600 MW Coal Greenfield	600	Coal	85%	3,483	5.1	7.9
300 MW Coal	300	Coal	85%	3,659	5.2	8.1
Coal Gasification CC	520	Coal	85%	3,778	5.3	8.3
300 MW Coal Greenfield	300	Coal	85%	4,208	5.3	8.7
Combined Cycle (CC)	300	Natural Gas	85%	1,044	8.8	9.6
Advanced Nuclear (AP1200)	1000	Uranium	85%	6,308	4.6	9.7
150 MW Coal Greenfield	150	Coal	85%	5,087	5.6	9.7
Switch Grass	100	Grass	85%	2,883	7.6	9.9
Whole Tree	100	Wood	85%	2,275	8.1	9.9
Municipal Solid Waste (MSW)	40	Refuse	85%	6,383	5.3	10.4
Combustion Turbine (HCF)	110	Natural Gas	85%	673	13.8	14.4
Fuel Cell	100	Natural Gas	85%	4,743	11.1	15.3
Bio-diesel (internal comb.)	5	Plant oil	85%	832	20.5	21.2
Intermediate						
Wind w/o backup (w/o REPI)	50	Wind	36%	2,068	1.4	6.6
Combined Cycle (CC)	300	Natural Gas	36%	1,044	9.1	11.1
Wind w/backup (w/o REPI)	50	Wind	36%	2,068	9.7	11.5
Wind w/o backup (w/o REPI)	50	Wind	24%	2,068	2.0	9.9
Combined Cycle (CC)	300	Natural Gas	24%	1,044	9.4	12.4
Wind w/backup (w/o REPI)	50	Wind	24%	2,068	10.0	12.8
Solar Thermal (Parabolic)	80	Sunlight	24%	3,551	4.1	15.3
Solar Photovoltaic (Fixed Plate)	50	Sunlight	24%	9,142	3.3	26.5
Peaking						
Compressed Air Storage (CAES)	100	Coal	5%	780	9.8	21.6
5 Hour Battery	100	Coal	5%	984	7.0	21.8
Pumped Storage	100	Coal	5%	1,274	8.3	24.9
Combustion Turbine (CT)	160	Natural Gas	5%	673	17.7	26.9
Combined Cycle (CC)	300	Natural Gas	5%	1,044	12.8	27.0
Aero-Derivative (LM 6000)	50	Natural Gas	5%	1,042	16.0	30.2
Diesel	5	Diesel	5%	832	38.1	49.5

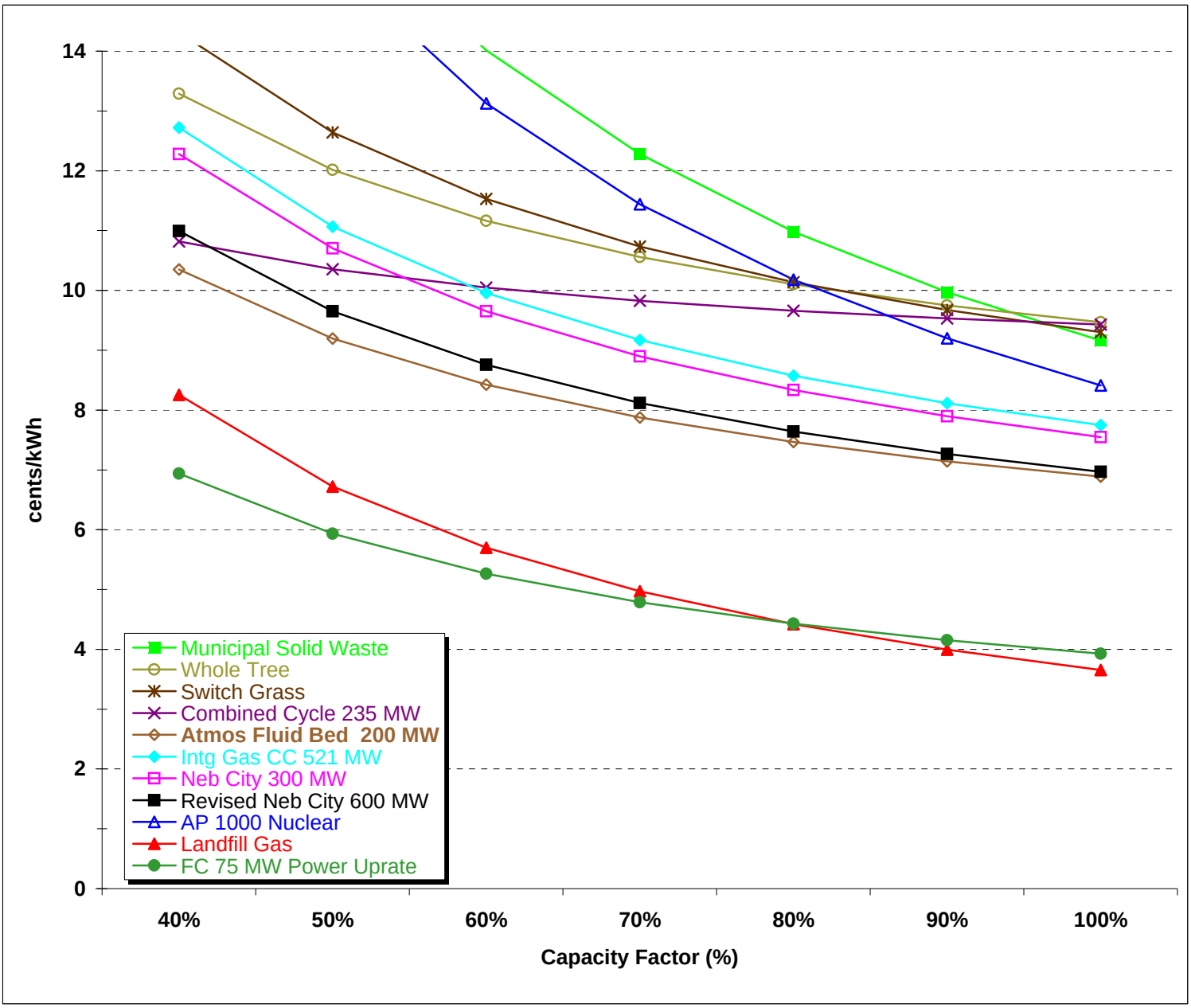
* Installed Capital Cost includes production plant, transmission plant, owner costs, decomissioning, renewals and replacements, escalation during construction, and interest during construction

** Operating Cost includes fuel, O&M, and environmental (SO_2, NOX, CO_2, Particulates) Costs

Attachment 13A

Baseload Screening Curve Analysis

Levelized 2009$

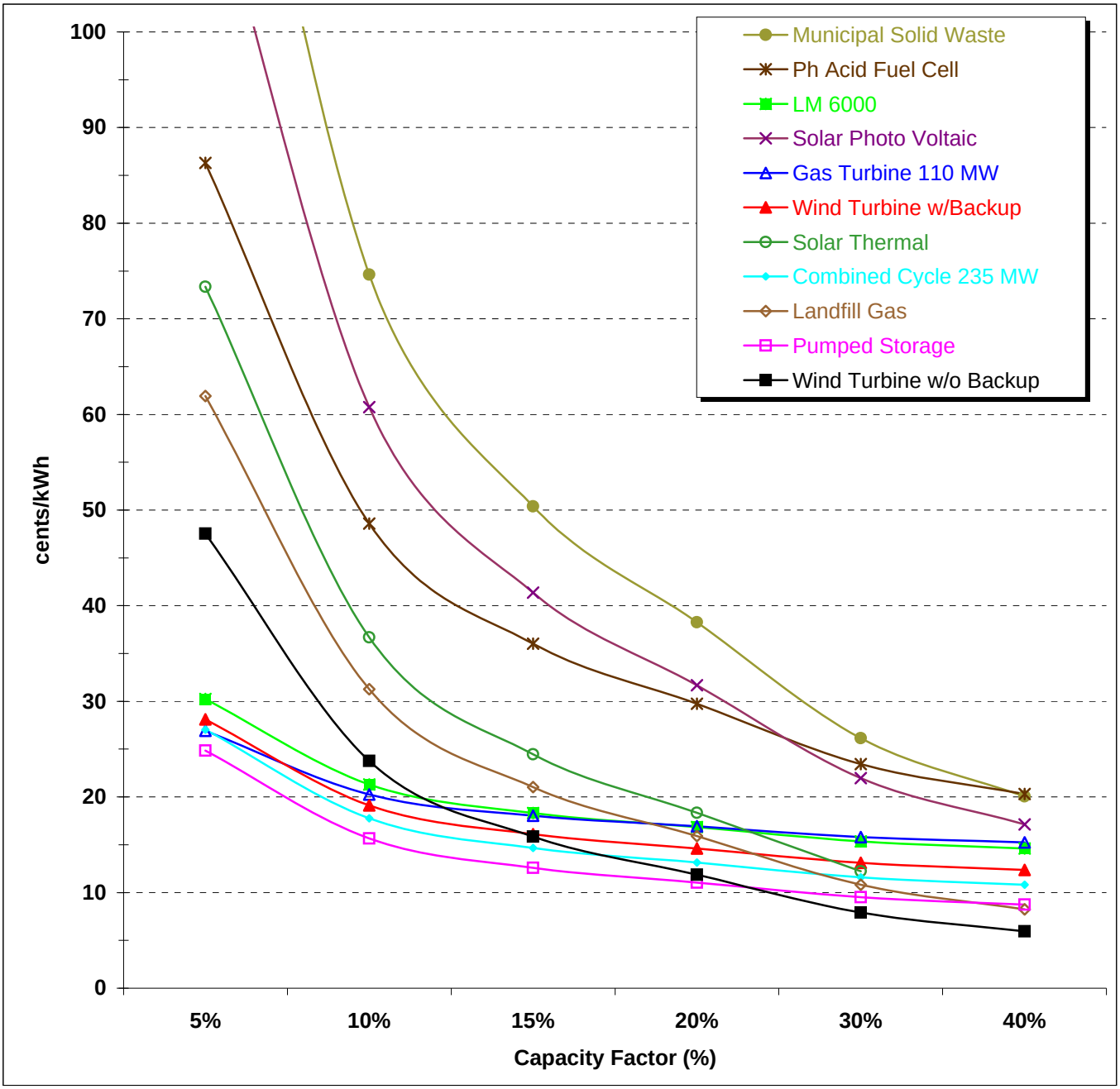


	Capacity Factor						
LEVELIZED COST (cents/kWh)	40%	50%	60%	70%	80%	90%	100%
Municipal Solid Waste	16.4	16.4	14.0	12.3	11.0	10.0	9.2
Whole Tree	13.3	12.0	11.2	10.6	10.1	9.7	9.5
Switch Grass	14.3	12.6	11.5	10.7	10.1	9.7	9.3
Combined Cycle 235 MW	10.8	10.4	10.0	9.8	9.7	9.5	9.4
Atmos Fluid Bed 200 MW	10.4	9.2	8.4	7.9	7.5	7.1	6.9
Intg Gas CC 521 MW	12.7	11.1	10.0	9.2	8.6	8.1	7.7
Neb City 300 MW	12.3	10.7	9.6	8.9	8.3	7.9	7.5
Revised Neb City 600 MW	11.0	9.7	8.8	8.1	7.6	7.3	7.0
AP 1000 Nuclear	19.0	15.5	13.1	11.4	10.2	9.2	8.4
Landfill Gas	8.3	6.7	5.7	5.0	4.4	4.0	3.7
FC 75 MW Power Uprate	6.9	5.9	5.3	4.8	4.4	4.2	3.9

Attachment 13B

Peaking/Intermediate Screening Curve Analysis

Levelized 2009$



	Capacity Factor					
LEVELIZED COST (cents/kWh)	5%	10%	15%	20%	30%	40%
Municipal Solid Waste	147.4	74.6	50.4	38.3	26.1	20.1
Ph Acid Fuel Cell	86.3	48.6	36.0	29.7	23.5	20.3
LM 6000	30.2	21.3	18.3	16.8	15.4	14.6
Solar Photo Voltaic	118.9	60.8	41.4	31.7	22.0	17.1
Gas Turbine 110 MW	26.9	20.3	18.0	16.9	15.8	15.3
Wind Turbine w/Backup	28.1	19.1	16.1	14.6	13.1	12.4
Solar Thermal	73.4	36.7	24.5	18.3	12.2	0.0
Combined Cycle 235 MW	27.0	17.8	14.7	13.1	11.6	10.8
Landfill Gas	61.9	31.3	21.0	15.9	10.8	8.3
Pumped Storage	24.9	15.7	12.6	11.1	9.5	8.8
Wind Turbine w/o Backup	47.5	23.8	15.8	11.9	7.9	5.9

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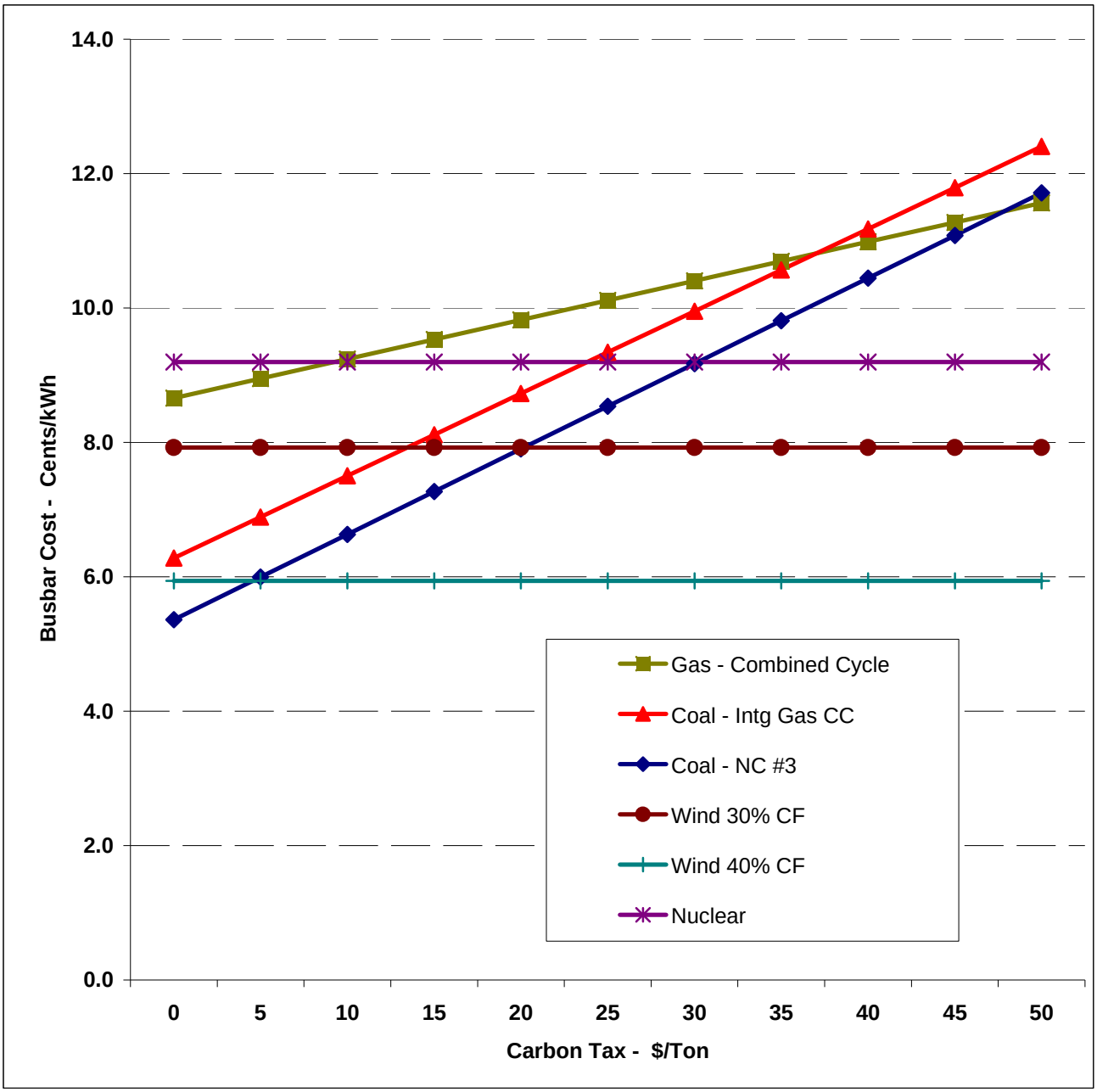
Attachment 13C

Busbar Cost - Function of Carbon Tax

Levelized 2009$



	Carbon Tax $/Ton					
LEVELIZED COST (cents/kWh)	0	10	20	30	40	50
Gas - Combined Cycle	8.7	9.2	9.8	10.4	11.0	11.6
Coal - Intg Gas CC	6.3	7.5	8.7	10.0	11.2	12.4
Coal - NC #3	5.4	6.6	7.9	9.2	10.4	11.7
Wind 30% CF	7.9	7.9	7.9	7.9	7.9	7.9
Wind 40% CF	5.9	5.9	5.9	5.9	5.9	5.9
Nuclear	9.2	9.2	9.2	9.2	9.2	9.2

Attachment 14

Ft. Calhoun

Expected Power Uprate Capacity Gains

Ft. Calhoun (MW)	2007	2008	2009-2012	2013
Jan	509.0	509.0	509.0	588.0
Feb	508.0	508.0	509.0	588.0
Mar	507.0	507.0	508.0	587.0
Apr	504.0	504.0	505.0	584.0
May	499.0	499.0	500.0	579.0
Jun	489.0	489.0	492.0	567.0
July	482.0	482.0	484.0	559.0
Aug	484.0	484.0	487.0	562.0
Sep	493.0	493.0	495.0	574.0
Oct	503.0	503.0	503.0	582.0
Nov	507.0	508.0	508.0	587.0
Dec	508.0	509.0	509.0	588.0
Avg	499.4	499.6	500.8	578.8

Derate %	2007	2008	2009-2012	2013
Jan	0.00%	0.00%	0.00%	0.00%
Feb	0.20%	0.20%	0.00%	0.00%
Mar	0.39%	0.39%	0.20%	0.17%
Apr	0.98%	0.98%	0.79%	0.68%
May	1.96%	1.96%	1.77%	1.53%
Jun	3.93%	3.93%	3.34%	3.57%
July	5.30%	5.30%	4.91%	4.93%
Aug	4.91%	4.91%	4.32%	4.42%
Sep	3.14%	3.14%	2.75%	2.38%
Oct	1.18%	1.18%	1.18%	1.02%
Nov	0.39%	0.20%	0.20%	0.17%
Dec	0.20%	0.00%	0.00%	0.00%

Uprates Attributable to Specific Projects

Appendix K	2007	2008	2009-2012	2013
Jan	-	-	-	-
Feb	-	-	-	-
Mar	-	-	-	-
Apr	-	-	-	-
May	-	-	-	-
Jun	-	-	-	-
July	-	-	-	-
Aug	-	-	-	-
Sep	-	-	-	-
Oct	-	-	-	-
Nov	-	-	-	-
Dec	-	-	-	-

HP Rotor	2007	2008	2009-2012	2013
Jan	-	-	-	79
Feb	-	-	-	79
Mar	-	-	-	79
Apr	-	-	-	79
May	-	-	-	79
Jun	-	-	-	75
July	-	-	-	75
Aug	-	-	-	75
Sep	-	-	-	79
Oct	-	-	-	79
Nov	-	-	-	79
Dec	-	-	-	79

Ft Calhoun Site Limit is Raised to 540 MW (from 492) -
approved by MAPP DRS - by 2013 this limit will need to be raised again

Years 2009 - 2012 Have Identical Monthly Ratings

Beginning Nov. 2008, Monthly Maximum Capacities Increased by 0 to 3 MW, Above 2007-08 Ratings.

Attachment 15

Suboptimal Cases

	Next Intermediate & Baseload			PU	Case Name	NPV	Delta	%
Benchmark Case	2014	CC C	2023 NC.J		B01	**10027**	Base	Base
Demand-Side Management								
A/C Cycling, 55 MW, 2010	2015	CC C	2023 NC.J		B00-A	**10035**	8	0.1%
A/C Setback Thermometer, 40 MW, 2010	2015	CC C	2023 NC.J		B00-B	**10030**	3	0.0%
A/C Cleaning, 16 MW, 2009	2014	CC C	2023 NC.J		B00-C	**10113**	86	0.9%
Comm High Eff Lighting, 5 MW, 2009	2014	CC C	2022 NC.J		B00-D	**10002**	-25	-0.2%
Wind and Advanced Batteries								
100 MW Wind, 2014	2014	CC C	2022 NC.J		B01-E	**10040**	13	0.1%
Wind 100 MW, 2014 & Advanced Battery, 100 MW, 2014	2017	CC C	2026 NC.J		B01-F	**10055**	28	0.3%
Storage Technologies								
CAES, 100 MW, 2014	2016	CC C	2026 NC.J		B01-A	**10054**	27	0.3%
Pumped Storage, 100 MW, 2020 & 2027	2014	CC C	2029 NC.J		B01-P	**9970**	-57	-0.6%
Advanced Battery, 100 MW, 2014	2016	CC C	2026 NC.J		B01-C	**10026**	-1	0.0%
Alternative Combustion Technologies								
Aero-Derivative, 100 MW, 2014	2016	CC C	2023 CC		B01-B	**10056**	29	0.3%
CT in 2014	2018	CC C	2023 NC.J		B01-D	**10092**	65	0.6%
Cass Conversion to CC, Force in 2016	2016	CC C	2023 NC.J		B01-G	**10053**	26	0.3%
No Neb City Expansion	2014	CC C	2021 CC		B01-J	**10122**	95	0.9%
No Coal, (Gas or Adv. Nuclear Only)	2014	CC C	2033 CC		B01-K	**10243**	216	2.2%
Alternative Technologies for Baseload								
No Combined Cycle	2016	CT	2022 NC.J		B01-H	**10634**	607	6.1%
Nuclear (Forced) - 300 MW	2014	CC C	2023 Nuc		B01-M	**10373**	346	3.5%
No Coal or Gas (Adv. Nuclear Only)	2023	Nuc	2028 Nuc		B01-L	**12896**	2869	28.6%
Integrated Gas Comb Cycle - 300 MW	2014	CC C	2023 IGCC		B01-N	**10112**	85	0.8%
Long Term Purchase 300 MW	2014	CC C	2023 Purc		B01-O	**10215**	188	1.9%
Neb City #3 in 2020	2014	CC C	2020 NC.J		B01-X20	**10031**	4	0.0%
Neb City #3 in 2023	2014	CC C	2023 NC.J		B01-X23	**10027**	0	0.0%
Neb City #3 in 2024	2014	CC C	2024 NC.J		B01-X23	**10044**	17	0.2%
Ft Calhoun Uprate Option, Baseload Coal Schedule								
Power Uprate	2014	CC C	2023 NC.J		B04-EPU	**10027**	0	0.0%
No Power Uprate Allowed	2014	CC C	2020 NC.J	N	B04-NO	**10099**	72	0.7%
$0/Ton CO2 Tax - General Case	2014	CC C	2021 NC.J	N	B06-C01N	**8170**	-1857	-18.5%
$0/Ton CO2 Tax - Power Uprate Required	2014	CC C	2021 NC.J		B06-C01PU	**8174**	-1853	-18.5%

Multi-Variable Sensitivity Cases

Evolving Wholesale Market Task Force Scenarios								
Mean Green - Nuclear, 600 MW RPS	2022	CC C	2028 CC	N	B03-MG	**9460**	-567	-5.7%
Status Quo - Coal, No RPS, No CO2 Tax	2014	CC C	2021 NC.J	N	B03-HD	**8170**	-1857	-18.5%
Bet the Farm - Coal, 200 MW RPS	2018	CC C	2033 CC		B03-BF	**8730**	-1297	-12.9%

Attachment 16

Sensitivity Cases

		Next Intermediate & Baseload			PU	Case Name	NPV	Delta	%
Benchmark Case		2014	CC C	2023 NC.J		B01	**10027**	Base	Base
Load Forecast (1.8%/yr)									
Low	1.0%/yr	2020	CC C	2033 NC.J		B02-S08L	**8038**	-1989	-19.8%
High	2.5%/yr	2014	CC C	2021 NC.J		B02-S08H	**12603**	2576	25.7%
Wholesale Prices Market ($52.0/MWh)									
60%	$31.2/MWH	2014	CC C	2033 CC	N	B02-S12L	**10162**	135	1.3%
80%	$41.6/MWH	2014	CC C	2033 NC.J		B02-S09L	**10383**	356	3.6%
120%	$62.4/MWH	2014	CC C	2020 NC.J		B02-S9H	**9346**	-681	-6.8%
No Interchange Sales		2016	CC C	2033 NC.J		B02-E3	**10798**	771	7.7%
No Interchange Purchases		2014	CC C	2029 NC.J		B02-E1	**10107**	80	0.8%
No Interchange Sales and Purchases		2016	CC C	2033 multi		B02-E2	**10957**	930	9.3%
Coal Costs (Base Case: $2.00/mmBtu Avg for NC & NO in 2009, see Attachment 6)									
Low	-25 cents/mmBtu	2014	CC C	2020 NC.J		B02-S01L	**9434**	-593	-5.9%
High	+30 cents/mmBtu	2014	CC C	2033 NC.J		B02-I1	**10691**	664	6.6%
Higher	+100 cents/mmBtu	2014	CC C	2033 NC.J		B02-S01H	**12143**	2116	21.1%
Very High	+180 cents/mmBtu	2014	CC C	2033 NC.J		B02-I2	**13722**	3695	36.9%
Debt Service and Study Variations									
Debt Service Coverage - 1.7		2014	CC C	2033 CC	N	B02-J1	**10830**	803	8.0%
Debt Service Coverage - 1.4		2014	CC C	2033 NC.J		B02-J2	**10513**	486	4.8%
No End Effects		2014	CC C	2023 NC.J		B02-C1	**6182**	-3845	-38.3%
Study Period 2009 - 2023		2014	CC C	2021 NC.J		B02-D1	**4806**	-5221	-52.1%
Gas Costs (Base Case: $10.83/mmBtu in 2009)									
Very Low	-$4.00/mmBtu	2014	CC C	2029 CC	N	B02-S05L	**7649**	-2378	-23.7%
Low	-$2.00/mmBtu	2014	CC C	2021 CC		B02-I4	**9065**	-962	-9.6%
High	+$2.00/mmBtu	2014	CC C	2022 NC.J		B02-I3	**10529**	502	5.0%
Very High	+$4.00/mmBtu	2014	CC C	2021 NC.J		B02-S05H	**10885**	858	8.6%
Coal Capacity Factors (85%)									
Low	80%	2014	CC C	2029 NC.J		B02-S03L	**10077**	50	0.5%
High	88%	2014	CC C	2021 NC.J		B02-S03H	**9948**	-79	-0.8%
Pulverized Coal Capital Costs ($3,029/kW)									
Very Low	$2,726 /kW	2014	CC C	2020 NC.J		B02-S04L	**9925**	-102	-1.0%
Very High	$3,635 /kW	2014	CC C	2033 NC.J		B02-S04H	**10147**	120	1.2%
Discount Rate (7.0%)									
High	12.0%	2014	CC C	2023 NC.J		B02-S07H	**3950**	-6077	-60.6%
Nuclear, Capacity Factor (92%) and Off-System Steam									
Low	90%	2014	CC C	2023 NC.J		B02-S02L	**10118**	91	0.9%
High	96%	2014	CC C	2021 NC.J		B02-S02H	**9814**	-213	-2.1%
Carbon Tax Legislation									
None - 0.0 $/ton CO2		2014	CC C	2021 NC.J	N	B06-C01N	**8170**	-1857	-18.5%
Low - 50% of Base, 2012 - 2032		2014	CC C	2021 NC.J		B06-C01L	**9159**	-868	-8.7%
Hgh - 150% of Base, 2012 - 2032		2014	CC C	2029 NC.J		B06-C01H	**10713**	686	7%
V Hgh - 200% of Base, 2012 - 2032		2016	CC C	2030 Nuc		B06-C01V	**11166**	1139	11.4%
Renewable Portfolio Standard									
15% RPS, 600 MW Wind		2015	CC C	2030 NC.J		B05-R15	**10154**	127	1.3%

Attachment 17

Wind Energy Cases

	Next Intermediate & Baseload		PU	Case Name	NPV	Delta	%
Benchmark Case							
No Wind Energy	2014 **CC C**	2023 **NC.J**		B01	**10027**	Base	Base
Wind Cost Variations in OPPD Service Territory							
Less $5/MWh, Require 200 MW Wind, 2019	2014 **CC C**	2022 **NC.J**		B05-OL01	**10138**	111	**1.1%**
Plus $5/MWh, Require 200 MW Wind, 2019	2014 **CC C**	2022 **NC.J**		B05-OH01	**10188**	161	**1.6%**
Plus $10/MWh, Require 200 MW Wind, 2019	2014 **CC C**	2022 **NC.J**		B05-OH02	**10214**	187	**1.9%**
Base Wind Cost, Require 200 MW, 2019	2014 **CC C**	2022 **NC.J**		B05-OL00	**10163**	136	**1.4%**
Wind Cost Variations - High Nebraska Wind Areas							
Less $5/MWh, 400 MW Wind Selected	2014 **CC C**	2029 **NC.J**		B05-L01	**9948**	-79	**-0.8%**
Less $10/MWh, 600 MW Wind Selected	2014 **CC C**	2030 **NC.J**		B05-L02	**9829**	-198	**-2.0%**
Less $15/MWh, 600 MW Wind Selected	2014 **CC C**	2030 **NC.J**		B05-L03	**9678**	-349	**-3.5%**
Plus $5/MWh, 0 MW Wind Selected	2014 **CC C**	2023 **NC.J**		B05-H01	**10027**	0	**0.0%**
Plus $10/MWh, 0 MW Wind Selected	2014 **CC C**	2023 **NC.J**		B05-H02	**10027**	0	**0.0%**
Less $5/MWh, Require 200, 400 MW Select	2014 **CC C**	2029 **NC.J**		B05-L01M	**9948**	-79	**-0.8%**
Plus $5/MWh, Require 200 MW Wind, 2019	2014 **CC C**	2022 **NC.J**		B05-H01M	**10087**	60	**0.6%**
Plus $10/MWh, Require 200 MW Wind, 2019	2014 **CC C**	2022 **NC.J**		B05-H02M	**10129**	102	**1.0%**
Lower Capacity Factor - 36% CF, No Wind	2014 **CC C**	2023 **NC.J**		B05-LCF01	**10027**	0	**0.0%**
High Capacity Factor - 45% CF, No Wind	2014 **CC C**	2023 **NC.J**		B05-HCF01	**10027**	0	**0.0%**
100 MW Wind - Require in 2009	2014 **CC C**	2022 **NC.J**		B05-W09	**10059**	32	**0.3%**
Require 100 MW Wind, 2014	2014 **CC C**	2022 **NC.J**		B01-E	**10040**	13	**0.1%**
Require 200 MW Wind, 2019	2014 **CC C**	2022 **NC.J**		B05-L00	**10044**	17	**0.2%**
Min 300 MW Wind, 400 MW 2016 - '19	2014 **CC C**	2023 **NC.J**		B01-I	**10040**	13	**0.1%**
Wind Outstate Nebraska - Sensitivity to Wholesale Prices and Fuel Costs							
40% Lower, Wind is not low cost option	2014 **CC C**	2033 **CC**	N	B02-S12L	**10162**	135	**1.3%**
20% Lower, Wind is not low cost option	2014 **CC C**	2033 **NC.J**		B02-S09L	**10383**	356	**3.6%**
20% Higher, Wind is not low cost option	2014 **CC C**	2020 **NC.J**		B02-S09H	**9346**	-681	**-6.8%**

Attachment 18

Selected Cases - Expansion Plans

Expansion Plans: Net Present Value Costs ($1,000's)

		-------- Evolving Market Scenarios --------			--- 2023 Baseload Options ---		---------- Input Sensitivity ----------			
	OPPD 15 Year Plan	Mean Green Scenario	Status Quo Scenario	Bet the Farm Scenario	Advanced Nuclear	Integrated Gasification Comb Cycle	No FC Power Uprate in 2013	40% Lower Wholesale Prices	High Coal Costs + $0.3/MMBtu	Very High Carbon Tax $5 thru 46/Ton
Case Name	**B01**	**B03-MG**	**B03-HD**	**B03-BF**	**B01-M**	**B01-N**	**B04-NO**	**B02-S12L**	**B02-I1**	**B06-C01V**
^ NPV Cost	10,027,326	9,460,364	8,169,686	8,729,884	10,372,637	10,112,220	10,099,284	10,162,309	10,690,854	11,166,197
^ NPV Diff. from Benchmark	N/A	-566,962	-1,857,640	-1,297,442	345,311	84,894	71,958	134,983	663,528	1,138,871
% Diff. from Benchmark	N/A	-5.7%	-18.5%	-12.9%	3.4%	0.8%	0.7%	1.3%	6.6%	11.4%
^ ($1,000's)										

Expansion Plans: Year-by-Year Facilities through 2036

Year										
2009	NC#2 331.5	NC#2 331.5	NC#2 331.5	NC#2 331.5	NC#2 331.5	NC#2 331.5	NC#2 331.5	NC#2 331.5	NC#2 331.5	NC#2 331.5
2010		Wind 100		Wind 100						
2011										
2012										
2013	FC PU 75	Wind 100		FC PU 75 Wind 100	FC PU 75	FC PU 75			FC PU 75	FC PU 75
2014	CC Conv		CC Conv		CC Conv	CC Conv	CC Conv	CC Conv	CC Conv	CC Conv Wind 100
2015										Wind 100
2016									Wind 100	Wind 100
2017		Wind 100							Wind 100	Wind 100
2018				CC Conv			Wind 100		Wind 100	Wind 100
2019			CT 160		CT 160			CT 160	Wind 100	Wind 100
2020		Wind 100					NC#3 J 330			
2021	CT 160	Wind 100	NC#3 J 330		CT 160					
2022		CC Conv				CT 160				
2023	NC#3 J 330			CT 160	Nuclear - 300	IGCC - 300		CT 160	CT 160	CT 160
2024										
2025								CT 160	CT 160	
2026				CT 160			CT 160			CT 160
2027										
2028		CC 530								
2029			Coal Jnt 300	CT 160			CT 160	CT 160	CT 160	
2030	CT 160				CT 160	CT 160				Nuclear 300
2031				CT 160				CT 160	CT 160	
2032					NC#3 J 330		CT 160			
2033	CC 530 Coal Jnt 300	Nuclear 300 Nuclear 300	Coal Jnt 300 Coal Jnt 300	CT 160 CC 530	CC 530	CC 530 NC#3 J 330	CC 530	CC 530	CC 530 NC#3 J 330	CC 530 CT 160
2034								CT 160		
2035	CT 160		CC 530	CT 160	CT 160		Coal Jnt 300	CT 160		CT 160
2036						CT 160				

Appendix A – Generation Technologies

The following provides a short description of the basic operating principals of each supply-side option and defines the underlying assumptions included in their costs.

Advanced Nuclear

Nuclear reactors are steam generator plants that use excess heat from a controlled nuclear reaction fueled by enriched uranium to produce high pressure steam. Advanced nuclear reactors are the next generation of nuclear plants. Following statutory requirements, the Nuclear Regulatory Commission (NRC) has set up a process by which reactor designs might be certified prior to any actual construction plans. The certification process seeks to reduce site development time by resolving common design issues prior to construction. Any new reactor built in the United States over the next decade or so would probably use designs certified by the NRC. Presently there are three certified new reactor designs. They are based on a standardized platform using current technology with a long safety and reliability track record. These designs are sometimes collectively called Advanced Light Water Reactors (ALWR). They incorporate more advanced safety concepts than the reactors previously offered by vendors. Of the three NRC-certified ALWR designs, only the General Electric Advanced Boiler Water Reactors (ABWR) has been deployed. Two ABWRs are operating in Japan with four more under construction in Japan and Taiwan. The hope is that a streamlined one step construction and operating license can be obtained based on these standardized designs. This one step license would reduce or eliminate the uncertainties associated with the ultimate operation of such a large capital investment. The idealized construction time is five years; but, based on passed experience, this time could increase substantially. As with all nuclear reactor units, advanced nuclear reactors are considered to be baseload units.

Advanced Batteries

Advanced Batteries is an energy storage technology whereby off-peak energy (usually coal), or an intermittent renewable energy resource, such as wind or solar is used to charge the batteries. The batteries are then used during peak load hours. Development on both the sodium-sulfur and the zinc-bromine advanced battery systems are considered mature and commercial availability is expected soon. Although batteries have virtually no emissions of their own, emissions from the plant used to charge them must be accounted for in an analysis. Batteries would normally be used as part of a modular design. Their fast time response to changing loads (20 ms) makes them excellent for peaking applications. Performance of the batteries is inherently better at part load than at full load. One big drawback of batteries is their inability to perform as intermediate or baseload units in case of forced or planned outages of other

units. Several advanced battery installations have undergone tests at electric utilities. The current estimated cost is approximately $800/kW to $1000/kW.

Energy storage systems, including advanced batteries, can be use to “shape” the energy generation of wind and other intermittent resources. Thus far, using such backup power resources has not been cost-effective.

Combustion Turbine

A combustion turbine (CT) unit is made up of an air compressor, a combustor (firing chamber), and an expansion turbine. Air is compressed into the combustor, mixed with natural gas or fuel oil and burned, producing hot gases that pass through an expansion turbine which drives the compressor and a generator. CT's are well suited for peaking applications due to their low capital costs, fast start-up times, and ease of varying generation output levels. High variable costs make them expensive alternatives for intermediate and baseload use. Required planning, licensing, and construction lead times are around four years. This relatively short period affords the planner greater flexibility in the decision making process than most other options. Since natural gas has a very low SO_2 content, no SO_2 control is necessary. These CT's can also be converted to Combined Cycle units at a later date.

Combined Cycle

A combined cycle (CC) unit is made up of one or more (usually two) CT's connected to a "waste heat to steam" recovery system on the exhaust end of the turbines. The steam is then directed through a steam turbine, effectively increasing the output of the CT's by about 50%. This increase in output requires a high capital outlay at no almost additional fuel cost. The CT's can still be operated both separately from the steam turbine or at part load with the steam turbine to increase the efficiency of the units. The high efficiency of the CC allows it to be competitive as an intermediate load option NO_X is controlled using selective catalytic reduction (SCR). SCR's are not available for CT's due to their high exhaust temperatures.

LM-6000 Combustion Turbine

LM-6000 is the first generation of aero-derivative engines that maximizes the commonality between aircraft engines and standard CT's. From an operational standpoint the LM-6000 behaves as the conventional CT. Today's units are typically sized at between 30-45 MW. Compared to the conventional power producing CT, the LM-6000 has higher capital and lower heat rate making it a more favorable resource option as capacity factor increases.

Compressed Air Energy Storage

Compressed air energy storage (CAES) uses a machine similar to a combustion

turbine to generate electricity. The main difference is that the modified turbine does not have a compressor stage. An electric motor driven compressor is used to pressurize air into a cavern, either rock, salt, or aquifer. This pressurized air is later released through the turbine in place of the normal compressor stage. Efficiencies of this system are gained through the use of off-peak energy to pressurize the cavern. Costs are highly dependant on the local geology.

Conventional Pulverized Coal

A conventional pulverized coal unit burns coal in a boiler to produce high pressure steam. The steam is directed through a steam turbine that is connected to a generator. Costs are based on a unit with low NO_X burners, an electrostatic precipitator (ESP) or baghouse for particulate control, a scrubber for SO_2 control, and cooling towers for the condenser. Pulverized coal units are a mature technology characterized by moderately high fixed costs and low variable costs. They are almost exclusively used for baseload units. Coal units require about 8 to 10 years plan, design, license, and construct. An additional unit at an existing site is usually less expensive then the first unit because of the savings in common equipment required to operate the plant (e.g., land, coal pile, coal handling, and water intake structure).

Internal Combustion (Diesel)

This system consists of a diesel powered engine similar to an automobile engine connected to a generator. It is typically used as a backup power system for large buildings that require uninterruptible power supplies. They are also used as black-start generators for various larger generating options. Diesel generators are generally less than 5 MW in size, have moderate capital costs, very high fuel costs, and are designed for a few hours of operation per year. Installing and maintaining large numbers of these machines is impractical making this option unattractive for large-scale utility applications.

Landfill Gas to Energy

Landfills generate methane as the biomass in the landfill decomposes. The landfill gas seeps through the landfill and exits into the atmosphere is not collected. Over the last 20 years, more than 360 landfills in the U.S. have recovered landfill gas and burned it to produce electricity or heat. An additional 500 landfills flare the landfill gas collected at the site. Many sites use the Landfill Gas as a portion of or all the fuel burned in internal combustion engines, small combustion turbines, or microturbines to produce electricity.

Fluidized Bed

A fluidized bed coal unit is similar to a conventional pulverized coal unit except for its method of SO_2 control. Limestone is mixed with the coal in the bottom

("bed") of the boiler before firing. A chemical reaction with the limestone traps most of the SO2. NO_x emissions are inherently low and particulates are controlled with an ESP or a baghouse. Costs associated with this type of SO_2 control technology currently are projected to cost more than an SO_2 scrubber. Atmospheric Fluidized-bed combustion boilers are now well established as a mature power generation technology. Currently, there are over 600 of these units in world-wide operation.

Fuel Cells

Fuel cells are a technology that makes a direct conversion of chemical energy (natural gas) to direct current electricity. This process is similar to a battery with a constant flow of chemical energy. Fuel cells are highly efficient due to their lack of an intermediate thermal stage typical of most generating options. They are considered technically mature and nearing commercial availability. The modular makeup of fuel cells makes a range of from 200 kW to 50 MW per stack feasible. Multiple stacks can be placed at each site to obtain the unit size desired. Rapid transient response capability provides excellent load following characteristics, and output can be produced in varying amounts of MVARs or megawatts, improving system power factors. Site selection is flexible due to quiet operation, low emissions, and air cooling. For systems designed to consume hydrogen directly, the only products are electricity, water and heat. When a fuel cell consumes natural gas or other hydrocarbons, it produces some carbon dioxide, though much less than burned fuel. Currently, fuel cells have high fuel costs as compared to other baseload options.

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) is simply a combined cycle unit that uses synthesis gas derived from coal for its fuel. There are currently 2 prototype projects in commercial operation. It is likely that there will be several commercial IGCC plants built with the next two years The conversion process from coal to gas is not a simple one and requires several steps to make the gasification process both environmentally safe and thermally efficient. The basic process involves mixing coal with oxygen (or air) and steam at high temperatures to produce raw syngas. This raw syngas undergoes a four-step process to cool the gas, remove the particulates, remove the sulfur compounds, and process the sulfur compounds into elemental sulfur for commercial sale. This processed gas is relatively clean and can be derived from almost any type of coal. All steps in the gasification process have been in use for years at industrial facilities and are considered mature technology. IGCC's are typically considered to be baseload units. The IGCC costs are slightly higher than a conventional pulverized coal unit with a scrubber and require about the same amount of time to plan, license, and construct.

Integrated Gasification Combined Cycle w/ CO_2 Capture and Sequestering

IGCC has been demonstrated at prototype plants, but adding facilities to capture and sequester the CO_2 would increase costs substantially. The coal gasification and CO_2 separation technologies have been demonstrated separately. FutureGen, a DOE-sponsored project, will include IGCC with CO2 capture and sequestering. FutureGen will consist of a 275 MW IGCC unit that will capture and sequester CO_2 in underground geological formations, where it could then possibly be used in an enhanced oil recovery process. Construction is scheduled to begin in 2009 with plant start-up in 2012. Depending on the results of FutureGen, and future CO_2 regulations, it might be feasible to retrofit other commercial IGCC plants with CO_2 capture and sequestering systems.

Municipal Solid Waste

Municipal Solid Waste (MSW) units burn residential and commercial solid waste that would otherwise end up in a landfill. These units are steam units similar to pulverized coal units except for their fuel. Municipalities are willing to pay tipping fees equal to the cost of landfills to encourage utilities to burn the waste. This causes the cost of fuel to be negative, that is, the more waste burned the less the cost of the power generated. An additional concern associated with MSW is the disposal of the ash since it may likely contain toxic substances.

Pumped Storage

Conventional pumped hydro energy storage uses an upper and lower reservoir. Water from the lower reservoir is pumped to the upper reservoir using off-peak energy. The water is then discharged through a turbine back to the lower reservoir during on-peak hours. Pumped storage costs are heavily dependant on the local terrain and costs may vary greatly from site to site. The upper reservoir is normally designed for about 10 hours of storage making it a good peaking to intermediate load unit. Very large units are usually required to take advantage of the economies of scale necessary to make pumped storage competitive with other options.

Solar Central Receiver

Solar central receivers use large parabolic troughs to focus or concentrate solar energy onto oil-filled pipes. The hot oil is used to create steam to drive a steam turbine generator. One unique advantage of this system is that natural gas or distillates can be used as a supplemental or replacement heat source for the solar energy, making the unit capable of intermediate or baseload operation. The main advantages of solar options are the free fuel and lack of emissions. Solar options would probably be used as intermediate load units.

Solar Photovoltaic

Solar photovoltaic cells convert solar energy to direct current electricity using a semiconducting material. Large areas of these cells are necessary to generate commercially significant quantities of electricity. While there are over 200 PV's on line, the largest of these units is only 5.3 MW. Use of modular designs will allow for much larger units than this to be built. One of the major drawbacks or these units is that they only work while the sun is shining which, as a peaking unit, is acceptable since peaks normally occur on hot sunny days in our service area.

Wind

Wind turbines look like a high-tech version of the old "Dutch" windmill. The fiberglass blades operate like airfoils connected to a horizontally mounted rotor. This rotor drives a generator which is generally 250 kW to 2.5 MW in size. While existing wind power stations generally have capacity factors greater than 30%, capacity factors of 40% are possible. These units can be constructed in a modular fashion making stations of any size possible. The power output of a wind turbine increases with the cube of the wind speed, that is, if the wind speed doubles, it provides eight times as much power. Minimum wind speed required for modern wind turbines is 12 MPH. A Nebraska wind site date study showed that the best wind sites are located in north-central and western Nebraska. Typical average wind speeds in eastern Nebraska are around 10 MPH. Wind turbines are only available when the wind is blowing within a prescribed range of speeds (12 to 30 MPH). Therefore, most resource options use fossil fuels that can be called upon to provide power whenever there is a need.

Wood

Generation using wood is an attempt to utilize a renewable fuel source. Wood units are simply steam turbine baseload units.