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OPPD

Omaha Public Power District

2011 Integrated Resource Plan

2012-2026

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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 RENEWABLES 3
1.4 PUBLIC PARTICIPATION 4
1.5 OPPD IRP AND INTEGRATED RESOURCE PLANNING COOPERATIVE 4

2.0 EXECUTIVE SUMMARY 5

2.1 FUTURE PLANNED CAPABILITY – OPPD 15 YEAR PLAN 6
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*
Table 1 – Peak Load Forecast, 2010 IRP Compared to 2011 IRP *12*
Fuel Forecast *13*
Table 2 - U.S. Total Consumption of Natural Gas – All Sectors *14*
Capacity Market Forecast *14*
Table 3 - Capacity Purchase Pricing *15*
Wholesale Market Forecast *15*
General Economic Assumptions *16*
Table 4 – General Economic Assumptions *16*
Environmental Emissions Risk Forecast *17*
Ethanol Industry *18*
3.2 ACCREDITATION AND CAPACITY 18
3.3 CONSTRUCTION COST ESTIMATES 19
3.4 STATE RENEWABLE TRENDS AND CARBON IMPACTS 19
Table 5 – Statewide Wind Total, End-of-Year, Nameplate Capacity *20*
Table 6 – Annual Generation of Electricity for 4 Comparison States *21*
Table 7 – Annual Coal Consumption used for Electricity Generation for 4 Comparison States *21*
Table 8 – Annual Natural Gas Consumption used for Electricity Generation for 4 Comparison States *22*

4.0 RENEWABLE ENERGY 24

4.1 OPPD RENEWABLE ENERGY POLICY, OPPD 10% RENEWABLE ENERGY GOAL 24
4.2 NEBRASKA LEGISLATION PASSAGE – CBED, NET METERING, WIND FOR EXPORT 25
C-BED *25*
LB-561 Revisions to C-BED and Renewable Generation Statutes *25*
LB-436 Net Metering and LB 65 of 2003 ..... *25*
LB-1048 Certified Renewable Export Facilities *26*
4.3 CURRENT OPPD RENEWABLE ENERGY PROJECTS 26
Petersburg Wind Facility Boone County Nebraska *27*
Flat Water Wind Facility Richardson County Nebraska *27*
NPPD Solicited Wind Projects *27*
NPPD Ainsworth Wind Energy Facility Brown County Nebraska *27*
Table 9 – Ainsworth, Elkhorn Ridge and Flat Water Wind Energy Facilities, Annual Capacity Factor *28*
Elkhorn Ridge Facility Knox County Nebraska *28*
Valmont Prototype Wind Turbine *28*
Elk City Landfill Gas Facility *28*
Fuel Cells and Distributed Generation *29*
4.4 RENEWABLE ENERGY RATE 29
4.5 TRANSMISSION, RENEWABLE GENERATION 30

4.6 NEBRASKA WIND STUDIES 30
4.7 RENEWABLE ENERGY PRODUCTION INCENTIVE....30
REPI Appropriations and Payments *31*
Table 10 - REPI Appropriation Summary....*32*
Status of Renewable Energy Production Incentive - REPI *33*
Status of Production Tax Credits - PTC....*33*
4.8 CLEAN RENEWABLE ENERGY BONDS (CREBS)....34
4.9 RENEWABLE ENERGY PORTFOLIO STANDARD 35
Potential Impact of RPS Mandate on OPPD *35*

5.0 ENVIRONMENTAL CONSIDERATIONS....36

5.1 ENVIRONMENTAL PROTECTION AGENCY REGULATIONS UNDER CLEAN AIR ACT 36
Table 11 – Pending EPA Regulations Principally Impacting Steam Power Plants....*38*
5.2 CAP AND TRADE PROGRAMS....39
5.3 EMISSION COMPLIANCE COSTS....39
5.4 SO_2 ALLOWANCES....39
5.5 NO_X EMISSIONS 40
5.6 MACT OR MATS, HAZARDOUS AIR POLLUTANTS, MERCURY CONTROL 41
5.7 PARTICULATE AIR POLLUTANTS....42
5.8 NEW SOURCE PERFORMANCE STANDARDS....42
5.9 MULTI-POLLUTANT CONTROLS (MPC) CONSIDERATIONS 42
5.10 CARBON DIOXIDE EMISSION COSTS....43
Carbon Dioxide Reduction Options....*43*
Existing Greenhouse Gas Intensity Measures *44*
5.11 MISSOURI RIVER – U.S. ARMY CORPS OVERSIGHT 45

6.0 SUPPLY-SIDE OPTIONS 47

6.1 SUPPLY-SIDE OPTION SCREENING 47
Combined Cycle Conversion of Cass County Station *49*
6.2 FORT CALHOUN STATION LONG RANGE PROJECTS 49
Rapid Refueling....*50*
HP Turbine Uprate *50*
MAPP Design Review Limits and SPP Transmission Ratings....*50*
6.3 CONVENTIONAL PULVERIZED COAL (PC) OPTION....50
6.4 COAL GASIFICATION/IGCC OPTION 51
Previous Demonstration Projects and Current Plans....*51*
Environmental Issues and Air Emissions *52*
Table 12 – Comparison of IGCC Emissions to NC2 Emissions *52*
Carbon Sequestration Opportunities....*52*
IGCC Conversion of Cass County Station *53*
6.5 ADVANCED NUCLEAR OPTION....54
Estimated Nuclear Plant Costs *54*
Drivers for Future Nuclear Units....*54*
6.6 NATURAL GAS OPTIONS 55
6.7 WIND ENERGY OPTION....55
Key Issues and Cost Uncertainties....*56*

7.0 DEMAND-SIDE MANAGEMENT PROGRAMS 57

7.1 HEAT PUMP PROGRAMS....57
7.2 HOME ENERGY AUDIT 58
7.3 RESIDENTIAL ENERGY STAR....58
7.4 WEATHERIZATION / LB1001LOW INCOME PROGRAM 58
7.5 SCHOOL BASED EDUCATION....59
7.6 RESIDENTIAL APPLIANCE RECYCLING....60
7.7 ENERGY ADVISOR....60

7.8 ENERGY EFFICIENCY EDUCATION AND TRAINING 60
7.9 RESIDENTIAL TIME-OF-USE (TOU) RATES 60
7.10 RESIDENTIAL AIR CONDITIONING LOAD CONTROL 61
7.11 GREEN POWER 61
7.12 CURTAILMENT LOAD PROGRAMS 61
7.13 EMERGENCY AND STANDBY GENERATOR PROGRAM 62
7.14 COMMERCIAL AND INDUSTRIAL ENERGY COMMISSIONING AND OPTIMIZATION (ECO 24/7) 62
7.15 INNOVATIVE ENERGY EFFICIENCY PROJECT (IEEP) PILOT 62
7.16 PRESCRIPTIVE REBATES 63
7.17 COMMERCIAL AND INDUSTRIAL ENERGY STAR 64
7.18 LED STREETLIGHT PILOT PROGRAM 64
7.19 PLUG-IN ELECTRIC VEHICLES (EV) 64
7.20 ENERGY RESEARCH PARTNERSHIP 65
7.21 2010 COMMERCIAL HEAT PUMP PROGRAM 66
7.22 OPPD'S 2010 DIGI RTU OPTIMIZER PILOT PROGRAM 66
7.23 DSM PROGRAM OPTIONS MODELED 66
Table 13 - Key Customer Programs Evaluated Per Industry DSM Tests *68*
Table 14 – Customer Program Cumulative MW Savings, Actual and Projected by Customer Class *69*
7.24 DEMAND REDUCTIONS IMPACT ON THE OPPD 15-YEAR PLAN 69
Table 15 – DSM Reduction Effects on Expansion Plan *70*
7.25 MEASUREMENT AND VERIFICATION 71

8.0 THE OPPD 15 YEAR PLAN AND SUBOPTIMAL PLAN ANALYSIS 72

8.1 THE OPPD 15 YEAR PLAN 72
Table 16 – OPPD 15 Year Plan *72*
Other Purchase and Sales *72*
8.2 UNIT PARTICIPATION OPTION 73
Nebraska City Station Assumptions *73*
8.3 RETIREMENT OF EXISTING UNITS 73
Table 17 – Age of Existing Baseload Units *74*
System Security *75*
8.4 DIVERSITY 75
8.5 RELIABILITY 75
8.6 DISPATCHABILITY 76
8.7 OTHER RISK FACTORS 76
8.8 SUBOPTIMAL SUPPLY-SIDE CASES 76
8.9 SUBOPTIMAL FUTURE RESOURCE OPTIONS 77
Table 18 – Suboptimal Options Analysis *78*
8.10 FT. CALHOUN POWER UPRATE, PROJECT TIMING ANALYSIS 78
Table 19 – Ft Calhoun Power Uprate Scenarios *79*
8.11 SUMMARY AND CONCLUSION 79

9.0 SENSITIVITY ANALYSIS 81

9.1 BENCHMARK CASE SENSITIVITY ANALYSIS 81
Table 20 – Load Growth, Wholesale Market, RPS and Carbon Sensitivity Case Analysis *83*
9.2 BENCHMARK SENSITIVITY CASES FOR CARBON PRICING 84
Table 21 – Carbon Pricing *85*
9.3 WIND ENERGY SENSITIVITY CASES 86

ATTACHMENTS 88

ATTACHMENT 1 – LOAD AND GENERATION CAPABILITY (SUMMER) 89
ATTACHMENT 2 – LOAD AND GENERATION CAPABILITY (WINTER) 90
ATTACHMENT 3 – LOAD AND CAPABILITY 91
ATTACHMENT 4 – ANNUAL SYSTEM PEAK DEMAND FORECAST 92
ATTACHMENT 5 – ANNUAL NET SYSTEM REQUIREMENTS FORECAST 93

ATTACHMENT 6 – FUEL FORECAST 94
ATTACHMENT 7A – ANNUAL WHOLESALE MARKET FORECAST 95
ATTACHMENT 7B – 2012 MONTHLY WHOLESALE MARKET FORECAST 96
ATTACHMENT 7C – WHOLESALE MARKET FORECAST SCENARIOS 97
ATTACHMENT 8 – ENVIRONMENTAL EXTERNALITY/ALLOWANCE TRADING FORECAST 98
ATTACHMENT 9 – SO_2 EMISSIONS AND ACID RAIN PROGRAM ALLOWANCES 99
ATTACHMENT 10 – NO_X EMISSIONS UNDER A MULTI-POLLUTANT CONTROL STANDARD 100
ATTACHMENT 11 – HISTORICAL CO_2 EMISSIONS 101
ATTACHMENT 12 – SUPPLY-SIDE OPTIONS 102
ATTACHMENT 13A – BASELOAD SCREENING CURVE ANALYSIS 103
ATTACHMENT 13B – PEAKING/INTERMEDIATE SCREENING CURVE ANALYSIS 104
ATTACHMENT 13C – BUSBAR COST – FUNCTION OF CARBON TAX 105
ATTACHMENT 14 – FT. CALHOUN EXPECTED POWER UPRATE CAPACITY GAINS 106
ATTACHMENT 15 – SUBOPTIMAL CASES 107
ATTACHMENT 16 – SENSITIVITY CASES 108
ATTACHMENT 17 – WIND ENERGY CASES 109
ATTACHMENT 18 – SELECTED CASES 110

APPENDIX A – GENERATION TECHNOLOGIES 111

ADVANCED NUCLEAR 111
ADVANCED BATTERIES 111
COMBUSTION TURBINE 112
COMBINED CYCLE 112
LM-6000 COMBUSTION TURBINE 112
COMPRESSED AIR ENERGY STORAGE 113
CONVENTIONAL PULVERIZED COAL 113
INTERNAL COMBUSTION (DIESEL) 113
LANDFILL GAS TO ENERGY 113
FLUIDIZED BED 114
FUEL CELLS 114
INTEGRATED GASIFICATION COMBINED CYCLE 114
INTEGRATED GASIFICATION COMBINED CYCLE W/ CO_2 CAPTURE AND SEQUESTERING 115
MUNICIPAL SOLID WASTE 115
PUMPED STORAGE 115
SOLAR CENTRAL RECEIVER 116
SOLAR PHOTOVOLTAIC 116
WIND 116
WOOD 116

1.0 Introduction and Purpose

Integrated Resource 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 all 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 2011 IRP considers a comprehensive list of supply-side resource technologies expected to be available during the fifteen-year study period of 2012-2026 to develop the OPPD 15 Year Plan. 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. Other options studied include capacity purchases, a power uprate project at Ft. Calhoun, pulverized coal with advanced pollution controls, coal with carbon capture and storage, simple and combined cycle combustion turbines, aero-derivative turbines, internal combustion engines (diesel), fluidized bed, coal gasification (IGCC) and advanced nuclear.

OPPD has implemented a number of demand side management (DSM) and energy efficiency programs. These programs have addressed customer and OPPD facilities. The 2011 IRP includes peak load reductions achieved by these efforts. A key objective of this effort is to delay the need for OPPD's next capacity resource by at least one year. In Section 7 it is shown the 50 MW gained through demand reduction programs will delay this resource by one year. DSM programs which contribute to these reductions include retrofit with efficient lighting, appliance recycling, prescriptive lighting and innovative technologies, high efficiency air-conditioners and air-conditioning control. DSM also includes curtailable programs structured under OPPD's rates. In 2007 OPPD established the division for Sustainable Energy and Environmental Stewardship (SEES). The SEES division analyzes a comprehensive list of DSM technologies options and selects programs best suited for OPPD. The SEES Division has in place measurement and verification tracking processes to verify energy efficiency and projected durability of the programs implemented. The IRP process can utilize 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. The 2011 IRP is based on current assumptions. OPPD is currently evaluating the impact of current, pending and future environmental regulations and the impact on OPPD's generating resources. This study will be completed in 2012 and will form the basis for the 2012 IRP

1.1 OPPD 15 Year Plan

The OPPD 15 Year Plan calls for an extended 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 2016 fall Ft. Calhoun outage. A new high pressure turbine will be installed which is designed to handle additional thermal energy. The next capacity addition after the Ft. Calhoun uprate will not be needed until 2021. This will be a peaking resource installed at Cass County Station sized at 160 MW. The peaking unit will be a simple cycle, natural gas fueled combustion turbine. In 2024 another peaking unit is needed also sized at 160 MW and installed at Cass County Station. The 15 year expansion plan includes no additional new intermediate or baseload generation through 2026. Wind turbines as an energy resource will be added to OPPD's generation mix. At the end of 2011 OPPD had 136.1 MW of wind by nameplate rating. OPPD has intentions to procure an additional 76 MW of wind energy from three new wind facilities located within Nebraska by the end of 2012. In the 2016 through 2020 timeframe another 180 MW of wind by nameplate will be added to meet the OPPD 10% Renewable Energy Goal. This goal is based on a percentage of OPPD customers' annual electrical energy requirements. 50 MW of capacity reduction will be achieved by customer demand reduction by 2012 through a combination of demand side programs.

1.2 Sensitivity Cases

The 2011 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 recent and pending 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 Renewables

Wind energy is the most economic form of expandable, renewable electrical generation available to OPPD. Landfill gas generation is actually lower cost than wind, but OPPD is currently utilizing the available methane gas at the Douglas County landfill through the operation of the Elk City Station. If additional landfill gas becomes available as the landfill grows, OPPD should utilize. 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 higher 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. Photovoltaic solar cell costs have decreased substantially. OPPD partnered with Creighton University in a project installing approximately 100 kW of photovoltaic solar and 4.8 kW of small scale wind on the Creighton campus. The 2011 IRP considers wind options in 80 MW wind farm increments. Under the base case CO_2 allowance cost assumptions, additional wind turbines beyond the OPPD 10% Renewable Energy Goal are slightly more economic on a net present value basis. Cost estimates for future wind is based on experience of wind projects in the Midwest region. The domestic wind energy business cycle is on an upswing in 2011 and 2012 as project sponsors attempt to bring their facilities on line before the current expiration date of the federal production tax credit at the end of 2012. Congress' decision whether to extend the production tax credit will have an impact on wind build-out beyond 2013, though regardless of a federal incentive or not, about half of the states have renewable mandates that must continue to be met.

Additional wind beyond the 10% goal may be required if a Nebraska or federal renewable portfolio standard (RPS) is enacted. Higher carbon cost scenarios leads to additional wind to be economical in the 2011 IRP analysis. Many industry analysts *expected* either a national renewable energy standard (RES), climate change law with attendant restrictions on carbon dioxide or an energy policy bill including both the above to pass in the 111th U.S. Congress (2009- 2010). However congress was unable to pass such a bill. With the stubborn return to a robust economy, Congress' appetite to put a cost on carbon dioxide emissions is low. The promulgation by the EPA of evolving air, water and solid waste regulations will impact OPPD's portfolio of generating units, the degree of which is still uncertain.

Renewable energy is discussed in Section 4. The 2011 IRP analyzes a variety of wind energy sensitivity cases. These cases are discussed in Section 9.3, and the results are shown in Attachment 17. By the end of 2012 Nebraska, statewide, will have 521 MW in wind nameplate capacity. OPPD will be purchasing the energy from 212 MW nameplate of that 521 MW. Nebraska wind facility development is largely financed by investors instead of directly by public power utilities, though so far nearly all the electrical energy generated from these wind farms is purchased by Nebraska public power entities. The Nebraska Unicameral passed LB-1048, a wind for export bill, in 2010. It remains to be seen whether this will spur further development of wind farms in Nebraska by wind

developers who find buyers for the wind energy outside the state. NPPD and OPPD, the two largest load serving entities in Nebraska, have made commendable progress through 2011 towards meeting each of their 10% renewable goals by 2020. Without significant interstate transfer capability additions to the transmission system, locating wind turbines in Nebraska for export of wind energy beyond state borders will be limited. OPPD now has first-hand operational experience in integrating approximately 135 MW nameplate of wind energy into generation dispatch and load balancing duties.

1.4 Public Participation

A formal public participation stage was part of the development of the 2011 IRP. OPPD held two multi month formal public comment periods during calendar year 2011 using the 2010 IRP as the basis for discussion. Public comment requests were invited per an insert placed in all customer's monthly billing statements. OPPD received very limited responses to these outreach efforts during 2011. As the IRP is a public document, OPPD customer-owners and the public at-large are also invited to offer their input on the planning process on an ongoing basis. All OPPD Board meetings are open to the public and the public can contact OPPD Corporate Communications offices directly. These processes meet the requirements of the Federal Energy Planning and Management Program.

1.5 OPPD IRP and Integrated Resource Planning Cooperative

The OPPD 2011 IRP meets federal regulations on the behalf of four additional entities: Peru State College, City of Syracuse, City of Tecumseh and the University of Nebraska at Omaha. These are full requirements customers of OPPD and also receive firm capacity and energy obligations from the Western Area Power Administration (WAPA). These four entities along with OPPD form an integrated resource planning cooperative that have joined together to complete this IRP and develop OPPD's 15 Year Plan. This planning cooperative also submits annual IRP Progress Reports to WAPA. OPPD solicits annual updates from these entities to complete the Annual Progress report.

2.0 Executive Summary

The 2011 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 along with additional generation capacity. Existing customer load curtailment and leased generation capacity programs are expected to reduce the peak demand by approximately 67 MW in 2012 and remain at this level throughout the planning period. Through sustainable energy programs sponsored by OPPD, customer-owners will reduce by 50 MW their contribution to OPPD's peak load. Primarily due to a softer economic outlook, the projections for future load in terms of peak load and net system requirements remain low and at similar levels to projections made in 2010. The lower load projection leaves the 75 MW Ft. Calhoun power uprate as the only additional baseload generation needed in the OPPD 15 Year Plan. Peaking capacity requirements are met in 2021, and again in 2024, with the addition of a single 160 MW combustion turbine fueled by natural gas and operating simple cycle in each of these years. 10% of OPPD's retail load requirements will be met with renewable energy by year 2020. Under Southwest Power Pool (SPP) capability rules wind generation has a very low capacity value, therefore wind does not assist OPPD in meeting SPP planning reserve requirements. OPPD's Load and Generation Capability is shown in Attachment 1.

During the past several years the Environmental Protection Agency has announced several rules which further restrict air, water and solid waste disposal from fossil fueled generation. The OPPD generation portfolio is over 50% coal fueled by accredited capacity. EPA's strengthening regulations will continue to impact the content of OPPD's generation portfolio as well as its operation. OPPD is in the process of determining the best and most cost-effective plan to meet EPA rules and regulations. A consulting firm has been retained to assist OPPD in these strategic decisions. This study will be completed in 2012 and will form the basis of the 2012 IRP.

2.1 Future Planned Capability – OPPD 15 Year Plan

The resources required to meet the forecasted OPPD retail load growth for the period 2012 -2026 are in the OPPD 15 Year Plan and include:

- Approximately 67 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 expected to be completed by 2017. Accomplished by replacing the high pressure turbine while increasing the plants thermal capacity. The uprate is expected to increase the July and August output by 75 MW. The remaining months' increase 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.
- In 2021 the addition of one simple cycle combustion turbine at Cass County Station fueled by natural gas adding 160 MW of capacity meeting OPPD's customer-owners peaking needs.
- 50 MW of demand side load reduction by 2012.
- Peaking capacity purchases as necessary in possible years 2019, 2020, 2022 and 2023.
- 160 MW peaking unit in 2024.

2.2 Summary and Analysis of Results

The current OPPD 15 Year Plan includes meeting baseload capacity and energy requirements with the Ft. Calhoun power uprate available in 2017. An additional 160 MW capacity through a peaking combustion turbine in 2021 and an additional 160 MW peaking turbine in 2024 will meet capacity requirements. Capacity purchases in some select summer seasons may also be required. No intermediate or baseload generation beyond the Ft. Calhoun uprate is required in the OPPD 15 Year Plan. The projected load forecast does not necessitate additional baseload.

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, though under a carbon tax, nuclear fuel costs may climb based on a clean energy premium. The combustion turbine peaking units will be installed at Cass County Station and will be fueled by natural gas. Longer term natural gas cost forecasts have moderated. In fact, the 2011 IRP natural gas price forecast between the years of 2012 – 2020 is the lowest projected for that future time period in over 8 years.

Sensitivity analysis determines the impact of changing key data assumptions on the OPPD 15 Year Plan. The Ft. Calhoun power uprate is economic in 2017 for all sensitivity cases studied. The 2021, 160 MW combustion turbine (CT) is economic in all

sensitivities except when using a 15 year economic study period instead of 30 years. The sensitivity with a high growth load forecast does replace the need for a CT in 2024 with a Cass County Station conversion to combined cycle in 2025. The conversion to combined cycle at Cass County is allowed as late as 2025, after 2025 the original 2 combustion turbines will have too many years of service to feasibly convert to combined cycle. An all-new combined cycle is considered as an option as of 2020, and beyond, and is allowed to be installed instead of the Cass conversion. Regardless, in the overwhelming number of sensitivities only natural gas fueled resources are the supply-side generation choices by 2026. Given the rising cost of coal as a fuel and the inclusion of a carbon tax in the model, natural gas fueled generation is the economic choice for fossil generation. The projected expense of new nuclear is also quite a bit more expensive than natural gas fueled generation even in the presence of a carbon tax. Looking beyond year 2026, and the need for the next baseload resource; advanced nuclear options may be economic.

Wind farms, sized at 80 MW in nameplate rating, are the increment of wind available in the IRP. The OPPD 15 Year Plan contains enough wind to meet the OPPD 10% Renewable Energy Goal. This is accomplished by assuming OPPD will have approximately 212 MW nameplate wind by the end of 2012 from existing and planned wind farms. Beyond this, one 20 MW wind farm is needed in 2016 and two 80 MW wind farms are needed in 2018 and 2020 to meet the 10% goal. In the IRP model, wind energy facilities are expected to be located in higher capacity factor wind areas, achieving a 40% annual capacity factor. These high wind areas are thought to be located outside OPPD's service area, e.g. north-central Nebraska. The Flat Water wind facility in the southern part of OPPD's service territory in Richardson County Nebraska; however, indicates there is potential for further wind facilities in OPPD's service territory. The results of the alternative wind cases are shown in Attachment 17.

After a down year in 2010, 2011 has seen robust growth in the installation of wind facilities across the Midwest. This growth will continue through 2012. The federal production tax credit (PTC) is set to expire at the end of 2012. If the PTC is to continue beyond end-of 2012, Congress will be required to enable continuation by affirmative vote. Meanwhile utilities in states with mandated RPS need to pursue their requirements. Wind energy is further discussed in Section 4 and Section 9.

Among the largest uncertainties when planning for future generation are changes in environmental regulations. Given the political nature of these types of regulations, predicting outcomes is difficult. To remain in operation, it is likely existing coal fueled 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). During 2011 the EPA has been refining rules it will enact under the CAAA as well as the Clean Water Act. The Clean Air Interstate Rule has been supplanted by the Cross State Air Pollution Rule which now rolls in Nebraska as participating state. In the late-hours before enactment a federal appellate court stayed the Cross State Air Pollution Rule. Section 316(b) has potential

impacts to power plants with once through cooling. Other EPA rules are in-line to take effect with necessary compliance in the next 3 to 4 years.

In 2009 the House of Representatives passed the American Clean Energy and Security Act (the ACES Bill) which was sponsored by house members Waxman and Markey. This bill capped greenhouse gases and included a renewable energy standard. The Senate was unable to pass a concurrent version of climate legislation so the 111th Congress ended without putting forth climate legislation which would have capped carbon-dioxide and other greenhouse gases emissions and imposed federal mandates on renewable energy. The courts granted the EPA authority to regulate CO_2 as a pollutant, and it remains to be seen how the EPA will limit CO_2 emissions from fossil fuel generation.

Given the high degree of regulatory uncertainty 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. The assumed costs of CO_2 allowances begin in 2015. In some prior IRPs this CO_2 tax was targeted to begin as early as 2012. The 2011 IRP base case assumes a CO_2 cost of $14/ton (beginning in 2015) and reaches $67/ton in 2035 in 2012$'s. The carbon tax is a cost for each ton of CO_2 emissions above pre-defined allowances. Without specific climate legislation on the horizon the 2011 IRP will tax emissions above that which could be achieved with combined cycle natural gas fueled generation. In addition to the base assumption for a carbon tax, the 2011 IRP also considered sensitivity cases as shown in Attachments 15, 16 and 17.

The 2011 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 Strategist's 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, commercial and industrial customers. DSM programs should be pursued: that are tailored to provide value to OPPD's customer-owners, lower the cost of electricity and which are beneficial to the environment. Coinciding with the implementation of these options is a measurement and verification process to verify energy savings through energy efficiency initiatives and the projected durability for such savings measured over time. DSM programs are further discussed in Section 7.

Public participation in the development of the IRP per Part 905 of the Code of Federal Regulations occurred during the calendar year 2011 as part of the process of creating the 2011 IRP and the OPPD 15 Year Plan. To this end, comments from the public were solicited on the 2010 IRP during two different multi-month periods of 2011. The public provided only one comment on the IRP.

2.3 Recommendations

Based on the results of the 2011 IRP, the following recommendations are made:

1. Place the OPPD 15 Year Plan into the OPPD corporate operating plan.
2. Replace the high pressure turbine at Ft Calhoun which provides an additional 75 MW capacity available for the summer 2017. 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. In prior IRPs this uprate was scheduled to be completed by January 1, 2013, but due to the 2011 flooding of the Missouri River and pressing regulatory issues, a postponement is necessary.
3. Plan for the next capacity addition to be a 160 MW natural gas fueled combustion turbine in 2021. This turbine will be located at the Cass County Station.
4. Monitor impacts of current and ongoing rule making by the EPA which will place more stringent requirements on air, water and solid waste emissions at electric power plants. The district is currently performing assessments of future resource strategies with potential decreased reliance on coal fueled generation. Potential expenses and practicalities must be carefully weighed in light of these rule making efforts. A full assessment is expected to be completed in 2012.
5. Continue to monitor the future cost of CO_2 as emissions are not likely to cost nothing what so ever. Currently, the electric power industry is under no specific pending plan to regulate CO_2. Previously characterized legislation would have added tens to hundreds of millions of dollars to annual operating costs. In the 2011 IRP the base assumption for evaluating future year costs includes a $14/ton cost of carbon allowances beginning in 2015 increasing to $67/ton in 2035 – in real 2012$s
6. Continue to study technologies for baseload generation options. Though no baseload option is needed in the OPPD 15 Year Plan, the district's next baseload decision will be based on economic, technological and regulatory dynamics. New coal generation may require carbon capture capabilities though currently there is no viable, scalable, solution; therefore costs are very speculative. Nuclear will maintain viability, especially in a carbon constrained electricity sector but must clear several hurdles before the next generation of a nuclear fleet is constructed in the U.S.
7. Continue to investigate and procure cost-effective renewable resources, predominantly in the form of wind energy, to meet the OPPD 10% Renewable Energy Goal and to increase the use of sustainable energy.

OPPD will need 400 MW of wind on-line by 2020 to meet this goal.

8. Continue to ascertain the impacts of OPPD as a member of the Southwest Power Pool (SPP) towards the system model used in IRP development. These include wholesale market prices, OPPD generating unit deliverability capability, availability of capacity purchase options and start of the SPP Integrated Marketplace in 2014.

9. Closely monitor efforts to expand the regional transmission grid as national strategic initiatives to curb greenhouse gas emissions focus on the U.S. 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; continue 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. Monitor OPPD's SO_2 allowances under the Acid Rain Program. Monitor SO_2 and NO_X emissions if the court stay is lifted on the EPA Cross State Air Pollution Rule.

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 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 all at the lowest possible cost to the customer.

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 2012-2026 Peak Demand and Net System Requirements forecasts, including conservation DSM programs, are listed in Attachments 4 and 5. Both the peak system demand and net system requirements forecasts are similar in the short and long-term, relative to last year's forecast. Both this year's and last year's forecasts reflect a future scenario of lower loads than forecasts created in 2008 and prior, pre-recession. See Table 1 for a comparison of 2010 and 2011 forecasted annual peak demands for 2012 through 2026. The economic outlook is for OPPD's commercial and industrial load to grow less rapid than pre-recessions projections. See Attachment 5 for a full net system requirement forecast comparison.

Table 1 – Peak Load Forecast, 2010 IRP Compared to 2011 IRP

Load Forecast, Annual Peak Demand (MW) as Forecast in 2010 IRP and 2011 IRP			
Year	**2010 IRP**	**2011 IRP**	**Change**
2012	2,452	2,470	18
2013	2,514	2,541	27
2014	2,566	2,585	19
2015	2,627	2,611	(16)
2016	2,671	2,651	(20)
2017	2,727	2,705	(22)
2018	2,774	2,753	(20)
2019	2,825	2,800	(24)
2020	2,859	2,835	(24)
2021	2,922	2,891	(31)
2022	2,973	2,939	(35)
2023	3,030	2,988	(41)
2024	3,073	3,031	(42)
2025	3,145	3,094	(51)
2026	3,204	3,148	(56)

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 in place for these 5 years. Contract coal in 2012 will cost around $1.86/MMBtu delivered. During 2012 approximately 54% of coal will be contract and the remaining percentage of coal requirements will be purchased on the spot market. Spot coal is expected to cost in the $1.89/MMBtu range through 2012. A weighted average of contract coal costs and spot market costs are used to determine the cost of coal at Nebraska City Station and North Omaha Station (see Attachment 6). Over the 15-year forecast period, coal prices are expected to slightly escalate in real terms – 2012$s. The coal industry may be entering a period of soft demand and limited growth in sales. Granted, without a federal climate change law, this softening will not be as drastic as it could have been, but EPA regulations seem destined to reduce this country's reliance on coal. However, off-shore export of U.S. coal is a growing business which helps offset decreasing domestic consumption. Carbon capture and storage likely will not become an aspect of a typical coal generating station anytime soon. 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 the latter half of 2008 the world-wide economy entered a recession causing prices of petroleum and natural gas to come off their mid-2008 highs in dramatic fashion. Henry Hub natural gas dipped to multi-year lows around Labor Day 2009 and then again in mid-January, 2012 (below $2.50/MMBtu), between these dates natural gas has been trading in a range, centering on $4.10/MMBtu. Natural gas prices are projected to be in the $4.50 - 7.50/MMBtu (nominal $'s) range in the next decade. Strong U.S. natural gas production helped by increasing shale gas production continues to provide a robust supply outlook. LNG import/export capabilities of the U.S. are growing slowly. With stronger than expected domestic production, the growing imports of natural gas expected a few years ago from LNG, now, looks to be unnecessary. In the long-term, an increase in demand from electric utilities for natural gas is expected to result in upward pressure on prices. Nationally, most new (non-wind) electric generation is expected to be fueled by natural gas. Interestingly, as shown in Table 2 U.S. total natural gas consumption in all sectors has been flat through 2001- 2008. High prices have most likely kept this demand flat through August 2008 followed by recessionary constraints for September 2008 through August 2010, even in the presence of gas as low as $2.00 – 3.00/MMBtu during this period. However, demand has returned with historically high consumption of natural gas for the 12 month period ending August 2011.

Table 2 - 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	21,535
2006 – 2007	22,637
2007 – 2008	23,335
2008 – 2009	22,715
2009 – 2010	23,600
2010 – 2011	24,428

For the 15-year forecast period covered by the 2011 IRP, natural gas will increase slightly in real terms considering the general inflation rate of 2.4%. 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 high 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. 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 3, in recent years, firm capacity prices have remained flat in the region. They are forecast to remain stable in the near future.

Table 3 - Capacity Purchase Pricing
($/kW-season)

YEAR	2005 IRP (2005 $)	2006 IRP (2006 $)	2007 IRP (2007 $)	2008 IRP (2008 $)	2009 IRP (2009 $)	2010 IRP (2010 $)	2011 IRP (2011 $)
2004	15.00	N/A	N/A	N/A	N/A	N/A	N/A
2005	15.00	N/A	N/A	N/A	N/A	N/A	N/A
2006	15.00	15.00	N/A	N/A	N/A	N/A	N/A
2007	15.00	15.00	15.00	N/A	N/A	N/A	N/A
2008	N/A	15.00	15.00	15.00	N/A	N/A	N/A
2009	N/A	N/A	15.00	15.00	15.00	N/A	N/A
2010	N/A	N/A	N/A	15.00	15.00	15.00	N/A
2011	N/A	N/A	N/A	N/A	N/A	15.00	15.00
2012	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, 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 (and retirements) 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 perform the load regulating duty during on-peak periods which are usually natural gas fueled combustion turbines or combined cycle units.

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, about 4,400 megawatts of coal fueled supply was built between the years 2001 – 2008. An additional supply of 1,792 megawatts and 3,856 megawatts were commissioned in 2009 and 2010, respectively. Currently about 6,000 megawatts of coal are under construction. In 2009 at least 18 coal unit projects were cancelled in the U.S. including an Air Force coal to liquid fuel project and an IGCC project, along with conventional coal generation projects of various sizes. The economic downturn, including the

unavailability of credit, and uncertain carbon regulation are common drivers for the cancellation of these projects.

Historically, OPPD has sold significant amounts electrical energy in on- and off-peak periods (non-firm power) to neighboring utilities. In years prior to 2009, around $100 million, or about 15 to 20% of General Business Revenues, came from wholesale market revenues. During 2009 through 2011 the prices for interchange energy have decreased from benchmarks of 2008 and show little sign of increasing in the next year. Annual wholesale market forecasts for non-firm energy are shown in Attachment 7A, and 2012 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 4 lists the general economic assumptions used in developing the forecasts for the 2011 IRP.

Table 4 – General Economic Assumptions

Inflation Rate	2.4%
Interest Rate	6.3%
Discount Rate	6.0%
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 2.4%. This is an increase from 2.0% used as the assumption in the 2010 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 is 6.3% up from 5.9% in the 2010 IRP. Inflation and interest rate forecasts are based on the March 2011 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 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 fueled combined cycle and, if technological advances take place, coal with carbon emission capture and storage. (Please see Section 5 for a discussion of environmental considerations.)

As discussed in Section 5, it is likely that CO_2 emissions will be regulated within the OPPD 15 Year Plan. The 2011 IRP assumes an increasing cost of carbon allowances beginning in 2015. 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 costs for CO_2 emissions in the IRP base case model.

OPPD will likely fall under new and more stringent regulations for SO_2, NO_X, and mercury emissions. In such a scenario all coal fueled power plants in the U.S. to remain operational will be required to install multi-pollutant control equipment in their facilities in the next 4- 8 years. In 2011 EPA released the Cross State Air Pollution Rule (CSAPR) which places caps on OPPD's SO_2 and NO_X emissions. CSAPR is the replacement rule for CAIR (Nebraska was not included in CAIR, but is included in CSAPR). CSAPR was stayed by the U.S. Court of Appeals for the DC Circuit just before it was to take effect. In December 2011 the EPA finalized the Mercury and Air Toxic Standards or MATS (known before hand as the Utility Boiler MACT rule).

OPPD is performing assessments on Nebraska City Unit 1 and North Omaha Station related to emission control requirements in response to potential enactment of such regulations as the MATS, NAAQS and CSAPR. These regulations will cause a great number of the nation's older coal fueled generating units without effective emission controls to shut down as it will be too expensive of an option to retro-fit them with new pollution controls. This assessment study will be completed in 2012.

As a result of prior dispersion modeling Nebraska City Unit 1 has been retrofit with a low NO_X burner; a project completed in late 2010. If CSAPR is reinstated by the courts, OPPD will need to mitigate some amount of SO_2 emissions from its coal fleet. Emission reducing options include reducing generation and thus interchange sales, buying CSAPR allowances from other utilities, burning ultra-low sulfur coal or installing control technology.

OPPD was able to observe early values of allowances before CSAPR was stayed by the courts. OPPD still remains under the Acid Rain Program but allowances to meet Acid Rain are plentiful. 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. The EPA's Cross State Air Pollution Rule would place an allowance cap on OPPD's NO_X emissions

Ethanol Industry

The ethanol industry is part of a multi-pronged national strategy as the U.S. strives for greater energy independence from foreign supplies. The incentives within the Energy Policy Act of 2005 towards ethanol help further drive this growth. The Nebraska Ethanol Board lists 24 operational ethanol plants in the state with 1 under construction, nearly complete. Nebraska is the second largest ethanol producing state in the U.S. The Cargill facility in Blair which OPPD provides electric service has the capacity to be a leading ethanol producer in the state. Ethanol plants have the ability to run continuously and thus can have load factors as high as 90%. Presently there are no new ethanol facilities under consideration in the OPPD service territory. The volumetric ethanol excise tax credit (VEETC), or blenders' credit, ended at the end of 2011. The U.S. Federal Renewable Fuels Standard continues to provide a minimum required amount of ethanol that must be blended in the U.S. fuel supply, 13.2 billion gallons in 2012 and15 billion gallons of corn based ethanol for 2015 and beyond.

3.2 Accreditation and Capacity

Nebraska City Station Unit 2 became commercial in May 2009 and now has a rating of 684.6 MW. A total of 7 participants have purchased a 50% total share of Nebraska City Unit 2's energy production.

Cass County Station is accredited for 323 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 2011 OPPD completed 6 years of purchasing wind power from the Ainsworth Wind Energy Facility near Ainsworth, Nebraska in Brown County. Under SPP Criteria for establishing the capacity benefit of wind turbines, Ainsworth has zero capacity benefit in the summer. It is also expected that Elkhorn Ridge, Flat Water and Petersburg will also have zero capacity after a 3 year period of initial operation. In the 2011 IRP future wind is deemed to provide no capacity credit to OPPD and therefore wind does not contribute to the OPPD planning reserve requirement.

OPPD became a member of the SPP RTO on April 1, 2009. The SPP reserve capacity margin is 12%; margin as a percent of total capacity. This equates to a load reserve margin of 13.64%; margin as percent of peak load. The reserve margin formula in Attachments 1 and 2 uses the margin as a percent of peak load. The 2011 IRP uses the 13.64% reserve requirement when projecting future resource needs.

OPPD's Net Generating Capability according to SPP Criteria is listed on Attachment 1. As previously mentioned wind turbines will receive zero or very small capacity benefit under SPP criteria.

3.3 Construction Cost Estimates

OPPD uses the EPRI December 2010 TAG-Guide for resource costs of fossil fueled resources including coal fueled, integrated gasification combined cycle (IGCC). OPPD has received current costs on wind turbine installations which are the basis of wind power evaluations.

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. Cost for coal generation with carbon capture and storage are highly speculative.

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

3.4 State Renewable Trends and Carbon Impacts

The following charts demonstrate trends in total electric generation, GWh, from all facilities and the fossil fuel consumption (coal in kTons, and natural gas in million cubic feet, used for electrical generation) contributing to the total electric generation. These strictly statewide totals are shown for Iowa, Minnesota, Nebraska and New Mexico for years 2001 through 2009.

Iowa and Minnesota data is included since both states have installed wind capacity to a larger degree than nearly any of the 50 states and also have a similar mix of traditional generation technologies to Nebraska: coal, natural gas and nuclear. Iowa does have a smaller share of nuclear generation than Minnesota and Nebraska and this is demonstrated by higher coal consumption. Though located outside the Midwest, New Mexico presents an example of a state that generates a similar amount of electricity to Nebraska but has more wind capacity than Nebraska, with 700 MW installed through the end of 2010 compared to 212 MW for Nebraska. Also New Mexico and Nebraska have the majority of their population concentrated in just a few metropolitan areas.

Minnesota and New Mexico have enacted mandated renewable requirements for its electrical utilities. Iowa has a voluntary renewable goal set by the governor. Nebraska does not have a mandated renewable requirement.

The coal data (kTons) shown in Table 7 is the quantity of coal burned to produce electricity from all electricity producers located in that state. Natural gas data meets the same application and is shown in units of million cubic feet in Table 8. The electric energy shown in Table 6 is the total electrical generation produced from all facilities within the boundaries of that state. Total wind installed in each state in terms of MW nameplate size is tabulated in Table 5, total installed within the state boundaries at year-end.

Table 5 – Statewide Wind Total, End-of-Year, Nameplate Capacity

(Source: EIA)

Year	Iowa (MW)	Minnesota (MW)	Nebraska (MW)	New Mexico (MW)
2001	318	303	3	0
2002	416	338	3	0
2003	462	468	13	204
2004	623	518	73	264
2005	820	687	73	404
2006	921	829	73	494
2007	1170	1139	71	494
2008	2661	1481	71	496
2009	3448	1636	152	597
2010	3665	2009	212	700
2011	n/a	n/a	326	n/a
2012			Proj. 521	

Table 6 – Annual Generation of Electricity for 4 Comparison States

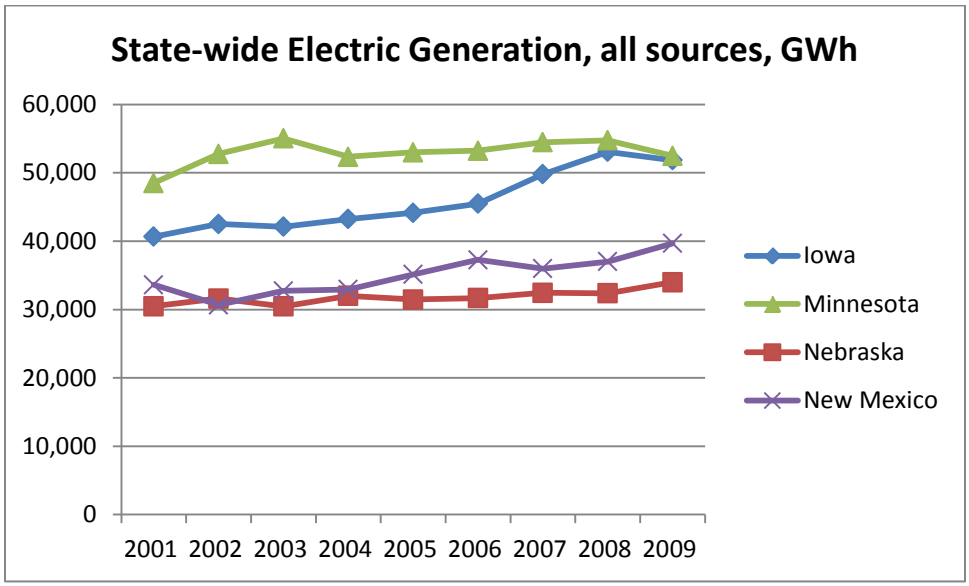


Table 7 – Annual Coal Consumption used for Electricity Generation for 4 Comparison States

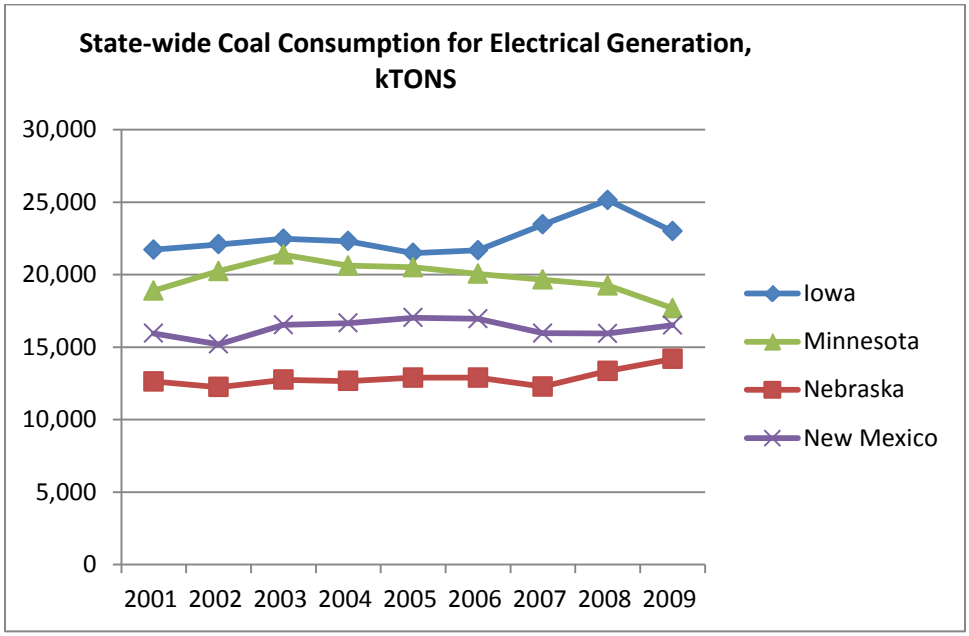


Table 8 – Annual Natural Gas Consumption used for Electricity Generation for 4 Comparison States

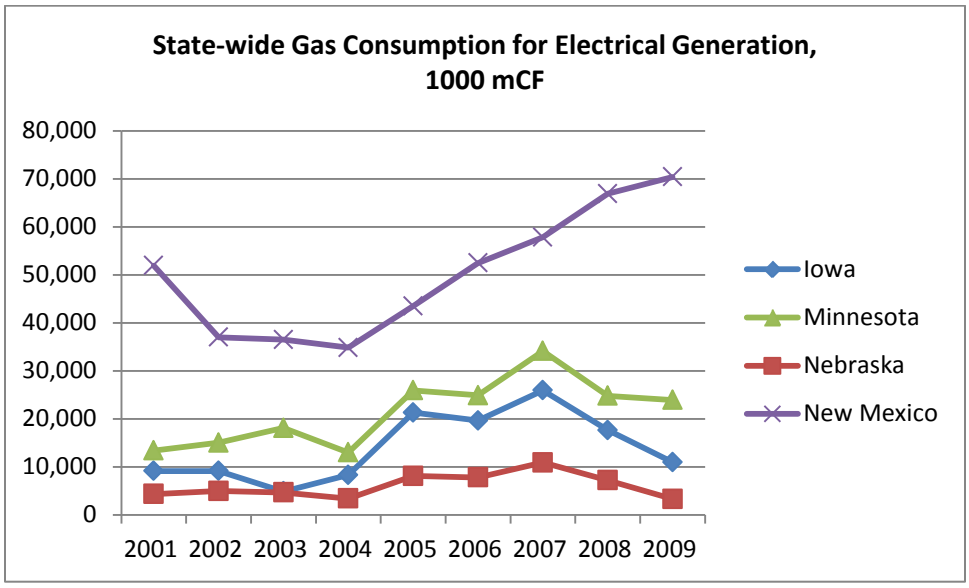


Table 6 shows statewide electricity production from all sources whether fossil wind or other. All states have increased their electrical generation since 2001. Iowa demonstrates the largest increase of over 20%. New Mexico is second with close to 20% over the years 2001 through 2009. Multi-year trends in electrical generation shadow population growth, status of commercial and industrial load as well as changes in quantity of generating facilities within the state.

Table 7 shows that coal use as a contributor toward electrical generation to be steady as would be expected from a baseload fuel. Minnesota shows the most noticeable declining trend in coal use after a high in 2003. Both Iowa and Nebraska added large coal units in 2007 and 2009 respectively which have led to some increase in coal consumption. New Mexico coal consumption reached plateau levels in years 2003, '04, '05, '06, then trended down but then picked up in 2009. Iowa's coal electrical generation was an all-time high in 2008 by over 6% above 2007 levels but did decline a bit in 2009. Nebraska and New Mexico set record coal electrical generation in 2009.

Table 8 shows an increasing reliance on natural gas as an electrical generation fuel. However in the Midwest states natural gas consumption trended back downward in 2008 and '09. New Mexico is most reliant on natural gas as their gas consumption for electricity production has steadily increased to 70 billion cubic feet in 2009. New Mexico has had some high gas consumption years going back to 2000 and 2001. All states have added gas generation capability in the last decade, either combustion turbines or combined cycle.

Year-to-year variations of fossil fuel use will largely depend on year-to-year variations in

customer demand, but many other circumstances such as extended nuclear or fossil unit outages and prices in the wholesale market will have an effect. Fossil use will be displaced to some extent as wind generation is added in the quantities seen for example in Iowa and Minnesota.

Trends in fossil fuel reductions may be more fully demonstrated in the next few years. Will the further addition of wind generation reduce CO_2 emissions from the utility/electrical generation sector by amounts proposed in various legislative initiatives? The wind nameplate rating has increased substantially in Iowa and Minnesota. Minnesota has decreased coal consumption annually starting in 2003, six straight years of reduction in coal consumption.

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 10% Renewable Energy Goal

In January 2009 the OPPD Board approved a goal for renewable energy at OPPD. The goal is to provide 10% of OPPD's retail customers' electrical energy requirements from renewable sources by 2020. OPPD's 2011 renewable portfolio of 95.7 MW of wind and 6 MW of landfill gas generation contributes about 4.0% of OPPD's retail customer energy needs. 40.5 MW of wind nameplate capacity added in late October, 2011 at Petersburg is projected to raise this percentage to about 4.9% for 2012. OPPD's use of renewable hydro power from Western Area Power Administration does not contribute to the goal. The OPPD 10% Renewable Energy Goal would not exempt OPPD from meeting a, larger than 10%, state or federal renewable mandate. Having the renewable goal in place certainly puts OPPD on a renewable trajectory in the event a higher renewable mandate applicable to OPPD comes to pass.

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, help address environmental issues and meet customers' desire for sustainable energy. OPPD believes a responsible approach to the 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 (now decommissioned), and a small-scale demonstration project in solar photovoltaic (PV) energy. During 2011 OPPD installed solar PV and a small wind spire at the new Omaha Service Center. OPPD is partnering with Creighton University in a solar PV and small scale wind turbine distributed generation project. OPPD will continue to test demonstration projects in order to retain updated information for accurately evaluating renewable technology options as their costs either decline or increase and their operational performance improves.

In the area of utility scale wind energy, as of the end of 2011 OPPD is purchasing wind energy from 136.2 MW of nameplate capacity through purchase agreements (Ainsworth, Elkhorn Ridge, Flat Water and Petersburg) and the Valley Station. Up to 76 MW of additional wind will be available from Broken Bow and Crofton Bluffs projects by

the close of 2012. If these projects are completed, OPPD will then have a total wind portfolio of 212.2 MW. This will position OPPD at just over one-half the needed renewable energy to meet the OPPD 10% Renewable Energy Goal by 2020 (including projected load growth by 2020) and obtaining this level of progress within only four years after the goal was put forth.

4.2 Nebraska Legislation Passage – CBED, Net Metering, Wind for Export

C-BED

The Rural Community Based Energy Development Act of 2007 (LB-629), or commonly referred to as C-BED, has led to the development in Nebraska of 80 MW of wind in 2009. C-BED projects are privately financed and require payments (no less than one-third of the power purchase payments) to flow 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 (see LB-561 discussion for changes). 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 federal renewable production tax credits or subsidies (see PTC discussion under Section 4.7).

LB-561 Revisions to C-BED and Renewable Generation Statutes

In 2009 the Nebraska Legislature revised portions of the C-BED statutes and further relaxed Nebraska Power Review Board (PRB) statutes as they pertain to renewable electrical generation. In LB-561, power districts were given the authority to agree to limit their exercise of the power of eminent domain to acquire a wind project. The PRB shall approve applications for wind and other renewable projects which supply but do not exceed 10% of the producers total energy sales if the applicant's governing body holds at least one public hearing on the renewable project. Under this statute revision, C-BED projects may apply in similar fashion if they establish a purchase power agreement exclusively with a Nebraska electric utility or utilities with a term of at least 20 years. With this revision it appears that larger wind projects than 80 MW will be allowed to be constructed in Nebraska as long the project meets the revised statutes. LB-561 also enacted an exemption to strict adherence to the financing requirements of C-BED statutes through the date of December 31, 2011.

LB-436 Net Metering and LB 65 of 2003

LB 436 passed during 2009 and is a net metering law. This allows a local distribution company to pay owners of customer-owned generation for that customer's electrical generation exported to the grid. For electrical energy in excess (sent to the grid) of the customer's own load requirements, the distribution company pays their avoided cost of electric supply to the customer. A qualified facility for net metering must use either methane, wind, solar, biomass, hydro or geothermal resources and have a rated

capacity below 25 kW. OPPD added a specific rate for net metering in October 2009; several customers are participating. OPPD prepares a netting settlement with the customer at the completion of each month

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 and LB-561 in 2009; along with the improving economics of wind generation has reduced the usefulness of LB 65 with respect to wind projects. However, the law retains its usefulness for other less affordable renewable technologies.

LB-1048 Certified Renewable Export Facilities

During the 2010 session of the Nebraska legislature the unicameral passed a bill with provisions to allow further wind to be developed in Nebraska without needing to meet the basic need statutes of the Nebraska Power Review Board. The bill allows for solar, biomass or landfill gas produced electrical energy as well as wind. Some key criteria must be met. At least 90% of the wind facility energy output must be exported to customer(s) located outside the state of Nebraska. If the facility is larger than 80 MW, 10% of the wind facility's output will be made available by offer to Nebraska electric suppliers such as OPPD. All or some of the Nebraska based electric suppliers may choose not to take the wind. Nebraska companies are not allowed to buy wind energy that would exceed a 10% renewable energy portfolio. Specifically for wind generating facilities, the bill exempts the facility from property tax. Instead the equipment will be subject to a nameplate capacity tax that is set at a level to be competitive with taxes imposed on wind facilities in other states.

4.3 Current OPPD Renewable Energy Projects

OPPD has developed a wind portfolio of 136.2 MW by the end of 2011. In 2011 OPPD installed solar and wind renewable generation at the recently completed OPPD Omaha Center. The Omaha Center construction and project received platinum LEED certification. OPPD partnered with Creighton University to install wind and solar distributed generation on the Creighton campus. Through the years OPPD has installed landfill gas fueled generation, a photovoltaic solar array, a mictro-turbine and fuel cell installations to receive first- hand experience with these technologies. OPPD continues to offer its customer-owners a green power rate which customers may voluntarily subscribe.

Petersburg Wind Facility Boone County Nebraska

The Petersburg Wind Facility began commercial operation on October 31, 2011. OPPD has an agreement with Third Planet Windpower, LLC to purchase 40.5 MW of nameplate wind energy from this facility located near the city of Petersburg, Nebraska. The facility is composed of 27, 1.5 MW GE turbines. OPPD is the sole purchaser of the energy from this wind facility.

Flat Water Wind Facility Richardson County Nebraska

The Flat Water Wind facility began commercial operation in late 2010. This is a 60 MW facility comprised of 40, 1.5 MW GE turbines which are mounted at a hub height of 80 meters. OPPD is the sole purchaser of the total production. Flat Water is located in OPPD's service territory in southwest Richardson County Nebraska near State Highway 105 and interconnects with OPPD's 161 kV transmission system. The facility is owned by Gestamp Company.

NPPD Solicited Wind Projects

NPPD continues to pursue involvement in wind energy projects. In March 2009 the Elkhorn Ridge wind facility was commissioned at 80 MW in which OPPD is a participant. The Crofton Bluffs project which is to be located in near proximity to Elkhorn Ridge is under development and will be 42 MW. NPPD is also working with developer(s) for projects near Broken Bow Nebraska. OPPD has plans to purchase 18 MW and 45 MW from two Broken Bow projects, respectively. NPPD has at least nine more sites across their territory where they are exploring wind opportunities. Laredo Ridge is an 80 MW wind facility commissioned in 2010 near Petersburg, Nebraska. OPPD did not purchase a portion of the energy from Laredo Ridge.

NPPD Ainsworth Wind Energy Facility Brown County Nebraska

OPPD purchases wind energy from 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. For calendar year 2011 OPPD paid about $52/MWh to NPPD for the wind energy from Ainsworth. Annual capacity factors for the Ainsworth facility are shown in Table 9. The capacity factor the district receives from its 10 MW nameplate share of Ainsworth is essentially equal to the total farm's capacity factor shown in Table 9. Slight differences result from OPPD receiving rounded whole megawatt values for each hour from Ainsworth whereas the total facility's output is metered to the nearest kWh.

Table 9 – Ainsworth, Elkhorn Ridge and Flat Water Wind Energy Facilities, Annual Capacity Factor

Year	Ainsworth Capacity Factor OPPD Share = 10 MW	Elkhorn Ridge Capacity Factor OPPD Share = 25 MW	Flat Water Capacity Factor OPPD Share = 60 MW
2006	43.4%		
2007	34.9%		
2008	34.6%		
2009	36.0%	28.1%, Apr-Dec	
2010	35.5%	28.8%	
2011	38.2%	36.5%	42.3%

Elkhorn Ridge Facility Knox County Nebraska

OPPD began receiving wind energy from Elkhorn Ridge wind facility in March 2009 adding 25 MW to OPPD's renewable portfolio. The total facility is sized at 80 MW nameplate capacity and is near Bloomfield Nebraska in Knox County. The Elkhorn Ridge wind facility is owned by Edison Mission Group and CBED interests. NPPD subcontracts OPPD's share along with the other participants' shares. The facility began commercial operation March 15, 2009 and is composed of 27, 3 MW sized Vestas turbines.

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 37.7% in April 2008. Annual capacity factors for the turbine have averaged 21% for the years 2004 – 2010.

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 eight nominal

800-kilowatt internal combustion engine/generator sets. Eight units are currently installed at the station. As of 3rd Quarter 2009 the landfill began producing enough methane to operate all 8 units simultaneously. The facility is now accredited for 6.08 MW. 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. 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 4.7 for further details). Since then, OPPD has received REPI funds for Elk City Station energy during fiscal years 2005, 2006 and 2007 and 2008. However the 111th U.S. Congress did not appropriate REPI funds for eligible renewable energy produced in fiscal year 2009 and fiscal year 2010 and therefore OPPD received no REPI funds for the energy produced in fiscal year 2009 and 2010.

Fuel Cells and Distributed Generation

OPPD began testing a 200 kW commercial-size fuel cell in 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. As a return the customers may claim all or some level of their energy usage comes from renewable energy sources.

OPPD began offering a renewable energy rate called the Green Power Program 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. OPPD takes the step of retiring equivalent renewable energy credits (REC) on behalf of OPPD's retail customers in the Green Power Plan. So the renewable energy that an OPPD customer purchases through the Green Power Program is certified and is directly correlated to energy produced from OPPD's renewable portfolio. By being retired on behalf of the customer, the REC is unavailable to be sold to others that may desire to procure RECs.

4.5 Transmission, Renewable Generation

The three Nebraska utilities of OPPD, LES and NPPD are members of the Southwest Power Pool (SPP) and these utilities' transmission systems are under the SPP RTO authority. SPP has processes to plan for transmission additions. Transmission expansion in Nebraska is expected through coordination with SPP's planning initiatives. These transmission additions will make addition of further wind feasible with regards to deliverability of the wind generation to load.

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.

A state-wide Nebraska Wind Integration Study was completed in December 2009. The Nebraska Power Association (NPA) directed the study effort. Funding was provided by the National Renewable Energy Laboratory (NREL) and a combination of matching funds from the 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 were retained to contribute regional nodal market analysis and intra-hour system statistical studies. A key finding is the expected 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 cases with 10%, 20% and 40% contribution of wind energy towards the state's total electrical energy requirements.

The NPA also 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.

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 10 - 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
2008	2009	$4,500,000	$2,384,470	$4,893,286	$1,800,000
2009	2010	$0 Appropriation			
2010	2011	$0 Appropriation			

Tier 1 qualifying facilities are facilities that use solar, wind, geothermal, ocean or closed-loop (dedicated energy crops) biomass technologies to generate electricity. Tier 2 facilities consist of land-fill gas and open-loop biomass technologies, such as biomass digester gas and plant waste material. 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 land-fill gas and other Tier 2 facilities receive a 40% payout, Elk City received $133,000 in REPI funds for FY 2005; $143,639 for FY 2006 generation; $205,451 for FY 2007 generation; and $230,497 for FY 2008 generation or 0.51 cents/kWh for the 2008 payout.

OPPD again applied for REPI funds for Elk City generation during FY 2009 and FY 2010. However congress appropriated REPI $0 for FY2009 and again in FY2010 so Elk City received no payment, as did utility owned wind generation facilities in the state. Annual REPI appropriations and payments on a U.S. wide basis are shown in Table 10.

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 2011 IRP does not include the 2.1 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 classification 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 facilities.

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. As noted above, congress appropriated $0 for REPI that would have paid out for generation during FY2010.

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 February 2009 the American Recovery and Reinvestment Act of 2009 extended the PTC for wind until December 31, 2012. The PTC is currently worth 2.2 cents/kWh for wind energy and is provided for the first 10 years of operation. The ARR Act of 2009 allows investors in wind energy (or other PTC eligible technologies) to opt for a federal business energy investment credit (ITC) or an equivalent cash grant from the U.S. Department of Treasury instead of utilizing the long time mainstay of this program, the production tax credit.

A history of the start and stop status of the PTC is as follows. 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. In October 2008, the Emergency Economic Stabilization Act was passed into law and extended the PTC credit for wind energy through December 31, 2009. As state above, the PTC is currently in effect until December 31, 2012.

4.8 Clean Renewable Energy Bonds (CREBs)

Clean Renewable Energy Bonds (CREBs) give state and local governments and cooperatives the ability to issue these tax credit bonds which provide the borrower with an interest free loan and the holder of the bonds with a tax credit (rather than collect interest on the principal) 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. CREBs were first issued under the Energy Policy Act of 2005. At that time nominated projects from governmental entities including public power districts received funds if they were under $3.2 million. The Elk City expansion project occurring at that time was estimated at $4 million and did not qualify for the first issuance of CREBs.

The Energy Improvement and Extension Act of 2008 and the American Recovery and Reinvestment Act of 2009 issued $800 million and $1.6 billion in CREBs, respectively.

The Treasury Department recently announced the allocation of $2.2 billion in CREBs to 805 public power companies and cooperatives nationwide. California and Washington fared well, with public power providers in those two states receiving about $600 million of the total. The majority of allocated money will go toward solar, wind, hydropower and biomass projects. The latest allocation is funded by the Energy Improvement and Extension Act of 2008 and the American Recovery and Reinvestment Act of 2009.

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 than the current estimated cost (without REPI). The current REPI incentive is 2.1 cent/kWh over a 10-year period, though rarely funded to this full amount.

4.9 Renewable Energy Portfolio Standard

In recent years, both a federal and Nebraska-based renewable portfolio standard has been introduced in U.S. Congress and in the Nebraska Unicameral. Neither action has been passed into law. The American Clean Energy and Security Act (ACES) passed by the House in 2009 included a 20% renewable energy standard however no version of this bill was enacted by the 111th U.S. Congress. A minimum of 26 states have enacted RPS legislation of varying percentage requirements and time deadlines. 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

As mentioned, in 2009 OPPD established a renewable energy goal to reach 10% renewable energy by 2020. OPPD will rely primarily on wind energy to meet the standard. At a capacity of 6,000 kW, the landfill gas fueled Elk City Station will contribute 3% of the amount of renewable energy required. At a capacity factor of 40%, 400 MW of wind energy capacity would be required to meet the 10% goal. Current cost estimates show that the capital cost for large-scale wind facility installations is approximately $1,800 - $2,600/kW for the production facility without transmission upgrade costs. Therefore, the capital expenditure to generate 10% of OPPD's energy from renewable sources could be well over $800 million for 400 MW nameplate rated wind energy assuming a 40% capacity factor 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 2011 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 and 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, other potential water and solid waste rule making and potential carbon (or climate change) legislation or regulatory rule-making are discussed in this section.

5.1 Environmental Protection Agency Regulations under Clean Air Act

The environmental impacts associated with fossil-fuel 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 fueled plants. Listed are key rules enacted under the amendments that impact electrical generators as well as evolving proposals as court decisions have shaped the rule making process:

1. Acid Rain Program – Acid Deposition Control
2. National Ambient Air Quality Standards (NAAQS); 6 criteria pollutants; NO_2 one hour limits in 2010, SIP needed; revision to SO_2 Standard in 2010
3. Final Amendments to Regional Haze Rule (RHR) – June 2005
4. New Source Review
5. Cross State Air Pollution Rule – to replace Clean Air Interstate Rule (CAIR), EPA desired enactment on January 1, 2012 stayed by the courts
6. Maximum Achievable Control Technology (MACT) – for electric utility boilers the rule was released as Mercury and Air Toxin Standard, industrial boilers are covered under a separate rule.
7. Greenhouse Gases Tailoring Rule

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 effect on more than one of the amendments above. The latest regulations issued by the EPA are the Regional Haze Rule (RHR) issued in June 2005; and revisions to the National Ambient Air Quality Standards (NAAQS), with new 1-hour NAAQS for NO_x and SO_2 finalized in 2010. The courts have vacated two rules of note: the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) originally issued in March 2005. Nebraska was not included in CAIR since at the time of issuance Nebraska emission sources did not adversely affect cities with NAAQS compliance

problems. In July 2010 the Clean Air Transport Rule (CATR) was introduced as the replacement for CAIR and Nebraska was brought into the collective states in the CATR area. In July 2011 the EPA issued the final CATR and referred to it as the Cross State Air Pollution Rule (CSAPR) to replace the vacated CAIR. As with the proposed CATR, Nebraska was included in the final CSAPR rule. On December 30, 2011 the U.S. Court of Appeals for the D.C. Circuit stayed CSAPR. CSAPR will be reviewed by the appeals court during 2012 and the future of CSAPR will hinge on the courts review.

Certain states have invoked levels for mercury emissions due to the now vacated Clean Air Mercury Rule. In December 2011 the EPA finalized the Mercury and Air Toxics Standard (MATS). Preceding the EPA release of this rule it was commonly referred to as the Utility Boiler MACT. The MATS rule specifically addresses hazardous air pollutants including mercury, and control technologies will be required to remove these pollutants from the flue exhaust. The EPA timeline gives utilities 3 years to adhere to this rule. An extension of 1-year may be granted by state permitting authorities to some generator owners who need more time to complete installation of controls.

A Supreme Court ruling in 2007 stated the EPA has the authority to regulate carbon dioxide (greenhouse gas) emissions. The greenhouse gas tailoring rule impacts new utility scale fossil-fueled generators and best available control technologies are within this framework. The full ramifications of this decision are still evolving to the extent it may impact electric utility emissions of greenhouse gases from fossil fuel plants.

Other rules are affecting other aspects of power plant operations besides air quality. Under the Clean Water Act (CWA), the proposed change to the 316(b) regulation impacts power stations relying on waterways for once through cooling operation. The rule is expected to be finalized in July of 2012 and may require changes to intake screens and/or additional fish studies at power plant intake structures. A potential EPA rule on coal combustion residuals including fly ash, bottom ash and scrubber wastes could reclassify these wastes as hazardous. Table 11 provides a summary of pending EPA regulations which will principally impact steam power plants fueled by coal but also may impact nuclear steam generators which utilize once through cooling.

In the fall of 2010, OPPD made retrofits to Nebraska City Unit 1 due to the Regional Haze Rule (RHR). Air quality in the OPPD service area currently meets the new, tighter daily standard on fine particles of NAAQS. 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.

Table 11 – Pending EPA Regulations Principally Impacting Steam Power Plants

Emission	Pollutant	Control Options	Status
Mercury and Air Toxins Standard, MATS; previously Utility MACT	Hazardous Air Pollutants: Hg, HCl, metals organics, others	Baghouse; Activated Carbon; Scrubbers; Sorbent Injection; Fuel Switching	Possible compliance by 2Q 2015 with possible 1-year extension; 3 years and 60 days after Federal Register
Cross State Air Pollution Rule, CSAPR	Reduce downwind contribution to ozone and PM2.5 non-attainment via control of precursor SO_2 and NO_X emissions	Scrubbers; SCRs; SNCRs; Low NO_X Burners; Fuel Switching; Sorbent Injection; Allowance Trading	Effective start of 2012 but stayed in U.S. Court of Appeals; court decision later in 2012
Regional Haze Program Best Available Retrofit Technology	Improve visibility in class 1 areas via reductions in SO_2, NO_X and PM2.5	Scrubbers; SNCRs; Low NO_X burners	Finalized in 2005, Nebr State Implementation Plan, SIP, is pending with EPA
National Ambient Air Quality Standards (NAAQS)	SO_2, NO_X, PM2.5, CO, ozone	Scrubbers, Baghouses,SCRs, SNCRs, Low nox, Sorbent Injection, Fuel Switching, Oxidation Catalysts	NO_X and SO_2 one hour standards set, further revisions to CO, ozone, PM2.5 ongoing
Cooling Water	Intake structures upgrades	Finer Screens	Proposed regulations in 2011
Waste Water		Treatment of return water, zero discharge (cooling towers)	Proposed regulations in 2012
Solid Waste , Coal Combustion Residue	Flue ash, bottom ash, scrubber	Phase out ash ponds, liner and other design requirements for landfills	Final Rule in 2011, ash ponds would have 5 – 7 years to close

5.2 Cap and Trade Programs

In a cap and trade program, utility generation units are allocated allowances based on desired regional or nation-wide emission reductions. 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. The EPA has declared the SO_2 cap and trade program under the Acid Rain Program a success.

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 cap become sellers in the allowance market.

Recent greenhouse gas legislation under the U.S. House bill authored by Markey and Waxman utilizes a cap and trade program for CO_2 with a portion of allowances granted to emitters (fossil fueled units) and retail electricity consumers. It is possible that allowances under a CO_2 program would be auctioned or sold instead of being allocated. With the 111th U.S. Congress concluding their session without passage of a bill based on Waxman-Markey cap and trade, it appears it may be a few years before a climate change bill with a cap and trade feature gains momentum in the halls of congress.

In July 2011 with the release of the EPA"s Cross State Air Pollution Rule an allowance trading program was included in the rule. The following are tradable allowances within the CSAPR: annual NO_X, seasonal NO_X, group 1 States SO_2 and group 2 States SO_2. Nebraska was designated to trade in the annual NO_X and Group 2 States for SO_2. The EPA Clean Air Mercury Rule originally possessed cap and trade but that entire rule has been vacated by the courts. Under the current MATS absolute limits from each stack will be instituted so a cap and trade on mercury will not be used.

5.3 Emission Compliance Costs

The costs associated with the effluent models in the 2011 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 fueled units when developing the OPPD 15 Year Plan. 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 is not projected to go deficit in SO_2 allowances as shown in Attachment 9. This is based on a SO_2 emission rate of 0.8 lb/MMBtu for North Omaha Units and Nebraska City Unit 1 for 2011 and beyond. 2009 was 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.

Industry analysis upon the release of CSAPR essentially relegated Acid Rain as being superseded by CSAPR. Apparently there is such an abundance of Acid Rain allowances across the U.S. as to render their value to little or nothing.

If the courts lift the stay on CSAPR, OPPD will implement SO_2 mitigation as SO_2 allowances may in initial years be valued in the $500 to $1,000/Ton range. OPPD is in a better position with respect to its allocated NO_X allowances under CSAPR.

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 Acid Rain program, NO_X emission requirements for coal fueled power plants were established. OPPD is required to meet certain NO_X emission rates at its coal fueled stations and modifications were required at OPPD stations. The North Omaha units and Nebraska City Unit 1 meet the Acid Rain Program. The Acid Rain Program does not include a nation-wide cap on emissions for NO_x nor provisions for a NO_x trading program. Beginning in 2008 lower annual average NO_X emissions were required at North Omaha Unit 4 and Nebraska City Unit 1 coal fueled units. These units were elected for early compliance, and current emission levels for these units are lower than the requirements set in 2008. The new source performance standards also established NO_X emissions limits for Nebraska City Unit 1 and are based on 3-hour contiguous performance.

In 2010 the EPA strengthened NAAQS for nitrogen dioxide (NO_2) by setting an hourly limit of 0.1 ppm. The EPA standard on ozone was modified in 2008. The existing standard was 0.08 parts per million (ppm) for ozone and is currently met by all counties in Nebraska and Iowa. The EPA lowered the ozone standard to 0.075 ppm. Counties in the OPPD service area are currently in attainment or unclassifiable under the 2008 ozone NAAQS. In January of 2010 EPA proposed to decrease the ozone standard further. However, in September 2011 the Obama Administration directed U.S. EPA to withdraw its reconsidered ozone NAAQS rule. This means that the 2008 ozone NAAQS of 0.075 ppm will remain in place and any review of that standard will take place in the

normal course of the five-year review.

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, 0.23 lb/MMBtu for Nebraska City Unit 1 with newly installed low NO_X burner, 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 levels established by the Cross State Air Pollution Rule (CSAPR). The CSAPR places limits and establishes markets for NO_X as well as SO_2. The CSAPR was to be implemented at the start of 2012 but was stayed by U.S. Court of Appeals. CSAPR places a cap on OPPD NO_X emissions. OPPD and Nebraska are under the annual NO_X emission limits along with 23 other CSAPR states. Nebraska is not included in the seasonal NO_X limits market. Due to the low NO_X burner installed on Nebraska City Unit 1 OPPD's allocations of NO_X allowances under CSAPR are obtainable.

OPPD has installed a low NO_X burner on Nebraska City Unit 1 in the fall of 2010 to meet the EPA Regional Haze Program regarding protection of visibility in Class I National Park and Wilderness Areas.

North Omaha Units 2, 3 and 5 have varying types of NO_X reduction equipment.

5.6 MACT or MATS, Hazardous Air Pollutants, Mercury Control

On February 8, 2008, the U.S. Court of Appeals for the Second Circuit vacated Clean Air Mercury Rule (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. This means in most states, mercury control will remain under section 112 of the CAA.

The EPA has developed standards which will reduce hazardous air pollutants (HAP), including mercury. While under development, the standard was widely referred to as the Utility Boiler MACT. Upon finalization of the rule EPA chose the title Mercury and Air Toxins Standard (MATS) for the standard. In December 2011 the EPA finalized MATS. The standard will limit emissions of hazardous air pollutants including mercury, hydrogen chloride, particulate matter, carbon monoxide and dioxins/furans. The effective date is April 16, 2012, 60 days after the February 16, 2012 Federal Register publication date. A three year compliance period is in place. An extra one-year beyond the three years is available if the state of Nebraska allows. This feasibly puts compliance by the spring of 2016. To maintain operation, OPPD's North Omaha Station's units and Nebraska City Unit 1 would need to be retrofit with some amount of pollution controls to remain operating.

5.7 Particulate Air Pollutants

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 under the NAAQS 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 µg/m^3 will be lowered in 2015 to 35 µg/m^3. The annual standard for $PM_{2.5}$ of 15 µg/m^3 will remain unchanged. Concerning coarse particulate matter, defined as ranging in size from 2.5 to 10 µm in diameter (PM_{10}), the EPA revoked the 50 µg/m^3 annual standard and leaves the 24 hour standard unchanged at 150 µg/m^3. According to the Nebraska Department of Environmental Quality's ambient air monitoring data, Nebraska currently meets the coarse particulate matter (PM_{10}) standard and the more stringent fine particulate matter ($PM_{2.5}$) standards, which will become effective in 2015.

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 fueled units require baghouses, spray dryer absorber (scrubber), 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 fueled units currently meet or exceed the existing applicable regulatory requirements related to emissions, there are potential federal legislative changes that would further restrict emissions requirements. These pending changes exist as legislative proposals and are generally referred to as Multi-Pollutant Control (MPC) proposals. However, in recent years the legislative debate has shifted to policy more specifically centered on carbon emissions.

Given the political nature of these types of regulations any prediction of MPC passage is hardly certain. Regardless of the form of initiative, it seems apparent that all coal fueled 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). Due to these expanding rules, a large portion of the nation's coal fleet will be retrofitted with pollution control equipment in the

next 4 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. Recent congressional environmental related initiatives are focusing on CO_2 and greenhouse gas emissions.

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 the intended regulations. OPPD's stations are not modeled to have the full array of available pollution controls. Since the Strategist simulation will purchase deficit allowances, a larger cost, or financial penalty, is placed on plant emissions in the 2011 IRP.

5.10 Carbon Dioxide Emission Costs

Attachment 11 shows OPPD's historical CO_2 emissions for the period 1990 through 2010. Currently the monetization of externalities as they relate to carbon dioxide (CO_2) is highly speculative.

In June 2009, the U.S. House of Representatives passed the ACES bill also referred to Waxman-Markey, HR2454. A concurrent Senate version of a climate change bill was not forthcoming during the 111th U.S. Congress and therefore climate legislation did not become law.

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. The EPA's greenhouse gas tailoring rule may require best available control technology (BACT) for fossil-fuel generation though it is not certain what technologies this rule would prescript. This cost is considered in the evaluation of resource options and selecting the OPPD 15 Year Plan.

The 2011 IRP assumes a carbon tax of $14/ton beginning in 2015 and increases to $67/ton tax is reached in 2035. This tax is placed on CO_2 emissions above and beyond predefined allowances. In addition to the base value, the 2011 IRP also considers sensitivity cases including a zero, low and high carbon tax case. The values are show in Table 21. OPPD will continue to closely monitor any developments related to future carbon emission costs, taxes, or related legislation.

Carbon Dioxide Reduction Options

OPPD has several options which can be implemented in relative short time-frames to reduce CO_2 emissions if CO_2 constraints are enacted by law or regulation. Of course these options will be more expensive than current practices. One option is to buy allowances if a cap and trade market is in place. Another is to generate a greater

portion of electricity requirements using natural gas. Another option is to reduce off-system sales. However, in a CO_2 constrained economy, these three options will strongly correlate in economic terms (the cost of CO_2 allowances, the price of natural gas, the cost of electrical energy in the wholesale market). In other words the price of any one of these is not going to change much without the other two following.

From a long-term point of view and since typical CO_2 reduction frameworks become stricter as time moves forward, OPPD has strategic decisions to make in a CO_2 constrained economy. Combined cycle units are more efficient than natural gas fueled simple cycle combustion turbine and steam cycle units. Today OPPD can only produce electricity using natural gas from combustion turbines at OPPD's peaking stations and through a steam-cycle at North Omaha Station's five units. Combined cycle units produce electricity using 30% less natural gas. Nuclear power is carbon free, though some amount of a carbon premium would be built into the cost of nuclear fuel. Enactment of CO_2 regulation would further kick-start the nuclear resurgence. Installing wind energy beyond OPPD's current 10% renewable goal is another alternative. Carbon capture and storage is a technology which would sustain the use of coal for electricity production although this process will add to the parasitic losses at coal stations.

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 replace existing coal generation with natural gas combined-cycle and/or nuclear units. The ability to accomplish large scale carbon capture and storage is greatly uncertain. OPPD will continue to monitor carbon legislation and regulation to assess the impact that such constraints could have on operations and the district's future power supply plan.

Existing Greenhouse Gas Intensity Measures

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 be pushed up slightly over the next 15 years because overall generation increases and nuclear generation becomes a lower percentage of total generation. The OPPD 10% Renewable Energy Goal will help mitigate this increase.

5.11 Missouri River – U.S. Army Corps Oversight

During the spring and summer of 2011 all three of OPPD's baseload stations were threatened by prolonged, flood stage, water levels on the Missouri River as the Corps drained record Missouri River basin runoff from the 6 mainstem reservoirs. Gavins Point Dam releases were at or above 140,000 cubic feet per second (cfs) for 74 continuous days. The prior highest, historical, rate of release from Gavins Point was 80,000 cfs. Management of water storage in the reservoir as authorized in the Corps' Master Manual received much scrutiny in the media and in public forums during and after the flooding. The year 2011 punctuated the level of disruption the Missouri River can present to the operation of OPPD's stations and to all enterprises located in the river's historical flood plain. Contrarily, in drought years low river levels may also lead to constriction in power generation limits due to thermal limitations.

The exact impact of EPA 316(b) has been evolving over several years. Under earlier forms, OPPD has pursued advanced inlet screens that would reduce marine life impingement over existing designs. With the recently proposed rule change to 316(b), even further reaching impacts may include the requirement to conduct up to 5 years of fish impingement and entrainment studies, the addition of fine mesh screens to existing intake screens, and the possibility still remains of the elimination of once through cooling as an acceptable means of cooling power plants. Such a decision by the EPA would have a large impact on many utilities across the country including OPPD which utilizes once through cooling at Fort Calhoun Station, North Omaha Station and Nebraska City Station Unit 1.

The federal government has introduced a requirement to perform a Missouri River Authorized Purposes Study (MRAP) as part of the Omnibus Appropriations Act of 2009. This study has funding of $25 million with the express purpose to review the original project purposes based on the Flood Control Act of 1944, and subsequent revisions, to

determine if changes to the authorized project purposes and existing Federal water resource infrastructure may be warranted. This study will take several years to complete and OPPD is recognized as a stakeholder.

Other 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, the power uprate option at Ft. Calhoun, the supply-side options that are being considered to meet OPPD's next capacity needs and assumptions regarding wind energy contributing to meet the OPPD renewable energy goal. The 2011 IRP does not recommend any new baseload construction in the OPPD 15 Year Plan. The load forecast does not require it. The power uprate project at Ft Calhoun is in the OPPD 15 Year Plan and will add 75 MW of baseload capability at the existing facility during OPPD summer system peak periods. Continuing evolution and implementation dates of EPA rules will influence decisions to maintain operation of OPPD's existing coal fleet

6.1 Supply-Side Option Screening

The 2011 IRP considered supply-side resource technologies expected to be available during the fifteen-year study period to develop the 2012-2026 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
Solar, Photovoltaic and Thermal

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
Pulverized Coal	-	Baseload
Nuclear	-	Baseload
IGCC	-	Baseload
Combined Cycle	-	Intermediate
Wind Turbine	-	Intermediate
Combustion Turbine	-	Peaking

In recent past years, almost all new power plants (non-renewable) in the United States have been natural gas fueled combustion turbines or combined cycle plants. Wind energy is experiencing the most rapid growth in percentage terms of installed portfolio. As mentioned earlier, a limited amount of planned coal fueled plants have been brought on-line. Actual new coal units commissioned are considerably low compared to the number of announced coal projects from earlier last decade (2000 – 2003). 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 fueled 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 the end of 2025.

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, provides OPPD with a continued diversified fuel mix of approximately 30% nuclear, 60% fossil and growing towards 10% renewable. Please refer to the 2006 IRP for a description of the above mentioned 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 low.

HP Turbine Uprate

The final project which would result in a power uprate would be the replacement of the HP turbine. This installation of the HP turbine will be delayed from the 2012 timeframe to around 2016. 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 and SPP Transmission Ratings

Prudent advanced planning for all aspects of the Ft. Calhoun power uprate is necessary and includes certainty that the increased generation capability of Ft. Calhoun is able to be exported from the station's buses without adversely impacting the regional transmission system. Before joining the Southwest Power Pool (SPP) on April 1, 2009, the operation of the OPPD and regional transmission system was subject to the policies of the Mid-Continent Area Power Pool (MAPP). OPPD received approval from the MAPP Design Review Subcommittee in 2009 to operate Ft. Calhoun at a net generation level of 607 MW. This is an increase from the previous limit of 540 MW. This limit is expected to be effective in SPP as well.

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 solid-waste emissions under various state and federal emissions control requirements. The evaluation of this option assumes that each new coal units will include flue gas desulfurization (FGD), selective catalytic reduction (SCR) and fabric filters to control SO_2, NO_X, Mercury and particulate emissions, respectively. Cooling towers are necessary. Low-sulfur sub-bituminous Wyoming Powder River Basin coal is assumed to be the primary fuel. In the 2011 IRP, the base analysis assumes one pulverized coal options, a unit with joint participation. This unit

would be sized up to 800 MW and would be a supercritical unit. OPPD would use 300 MW of the capacity.

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 technology. Please see Table 12 for a comparison of typical emissions from an IGCC plant to the emissions from Nebraska City Unit 2.

Currently, IGCC is approximately $1,100/kW higher in capital costs compared to building pulverized coal. 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.

At some future point the only viable new coal fueled generating station, whether IGCC or pulverized coal, will need to possess full CO_2 capture capability. A commercially available CO_2 capture technology is not readily available. Estimates of busbar costs for a coal unit possessing a CO_2 capture technology are higher than advanced nuclear. Select new coal units continue to be permitted for construction, but even in the absence of federal greenhouse gas regulation, new coal units receive considerable public resistance based on global climate change concerns.

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 a few integrated gasification combined cycle (IGCC) units under development. In the 2011 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 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. Recently Mississippi Power has put forth efforts to get state commission approval for an IGCC unit that would use regional coal. Planned completion date is still several years away. Duke Energy is constructing the Edwardsport IGGC plant in Indiana. This project has experienced cost over runs and has been subject to regulatory scrutiny by the state of Indiana. Taylorville IGCC is a

project in Illinois with uncertain future status. A commercial coal gasification plant operates in North Dakota but is not used for electricity generation. 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. Given the state of the economy in the past several years initiatives for IGCC along with other large expense generation options such as pulverized coal and nuclear have lost much of their fervor. The fact that the IGCC fuel is coal, ties it to the same current carbon pitfalls as pulverized coal technology.

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 permitted emissions from Nebraska City Unit 2 in Table 12. The IGCC emissions shown in Table 12 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 these are upper limits for Nebraska City Unit 2, actual performance is under. As illustrated in Table 12, IGCC emissions are not significantly different than emissions from Nebraska City Unit 2. Specific mercury emission controls remain 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 12 – 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
	No permit for CO_2	
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 in the United States. Nuclear fuel costs are expected to be stable over the long term as compared to volatility experienced in the natural gas market. Increased regulation of CO_2 and other emissions will likely create additional barriers to baseload gas- and coal fueled plant construction. A carbon constrained future has the potential to make nuclear more cost effective in comparison to gas or coal fueled units. A few U.S. utilities are studying the option of adding new nuclear capacity to their generation portfolio. In the 2011 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 one-half share of a 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 (without CO_2 capture technology). The capital cost of an AP1200 advanced nuclear design power plant is estimated at $4,131/kW (2012$'s). This is the cost of the plant only. The installed capital cost is $6,058/kW. The AP1200 levelized busbar cost, operating baseload in the Midwest U.S., is 9.9 cents/kWh which includes decommissioning, transmission, owner costs, fuel, operations and maintenance and interest.

Drivers for Future Nuclear Units

There are a number of regulatory, economic, technological, and environmental drivers that are leading 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 continues to be a potential 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 is a definite option in the mix. Given the state of the economy in 2011 initiatives to construct new nuclear generation in the U.S. have relented a bit. Several U.S. utilities remain strong advocates of a nuclear build-out. However, the financial sector may be a bit more cautious before providing credit.

The earthquake and tsunami off the coast of Japan in March 2011 severely crippled the Fukushima-Daiichi station and re-magnified safety concerns with nuclear power around-the-world. Following the Japan catastrophe U.S. nuclear project plans still made some advances. In the latter half of 2011 the U.S. Nuclear Regulatory Commission granted the Westinghouse AP1000 design a design certification amendment as the reactor containment and shield building designs had been hardened to higher levels. As of the end of 2011 the Southern Company's Vogtle project is an example of one nuclear project that is progressing.

6.6 Natural Gas Options

Given the risks and difficulties of pursuing new coal fueled and nuclear baseload options, natural gas is the fuel of choice for most new dispatchable generation in the U.S. Low cost natural gas increases the attractiveness of this alternative. Combined cycle natural gas units have fuel costs that are now much closer to coal by historical standards. Combined cycle capital costs are considerably lower than pulverized coal, IGCC and nuclear. The largest risk for natural gas is fuel price as the prior decade demonstrated the volatility in pricing this commodity. Electricity produced from combined cycle is not carbon free, but produces approximately one-half the CO_2 emissions as pulverized coal.

6.7 Wind Energy Option

The 2011 IRP OPPD 15 Year Plan includes wind installations to meet the OPPD 10% Renewable Energy Goal. Wind energy is the renewable of choice to meet most of this 10% goal. The goal will be accomplished by having 400 MW of nameplate wind available to OPPD by year 2020. So far OPPD has procured its wind energy through purchase agreements with third parties with the exception of the Valley turbine. It is likely that OPPD will purchase most, if not all its future wind requirements through such agreements. Sensitivities of a 15% and 20% renewable goal case are considered. These cases are discussed in Section 9.3.

Key Issues and Cost Uncertainties

As the rate of wind project development increases in Nebraska, wind equipment cost projections for future build-out is more certain. Nebraska currently has 335 MW of wind, 11 MW of this total is in the Western Interconnection. Up to 197 MW of new wind is fairly certain by the end of 2012. NPPD is stating that the state's transmission system is reaching its limits with respect to accepting more generation. Each new wind project will likely require some amount of incremental transmission build-out to get the wind energy to load while maintaining a secure operating state of the transmission system. It should be noted the 345 kV transmission system within Nebraska has received recent additions with more planned in the near term, though these were not completed as a result of wind energy being a driver.

Integration of significant amounts of wind as an intermittent energy resource is an on-going source of study. The NPA Wind Integration Study derived costs to integrate wind at 10%, 20% and 40% penetrations and calculated the increased need for regulating reserves which are carried by the thermal generation fleet. During high wind, low load periods, system operators may be faced with the decision to take baseload generation off-line. Economic incentives may be necessary to keep an adequate amount of back-up thermal generation on line. The idea that wind generation must run full out (to the extent that wind is available) at all times might also need to be rethought to consider purposeful curtailment of wind energy in some situations.

Coordinated initiatives on the regional (SPP), inter-regional (MISO, SPP, PJM, TVA, etc) and national levels have approached wind generation from the perspective of tapping the wind resources of the Great Plains to the extent that it contributes significantly to, for example, a 20% national renewable energy portfolio. This level of perspective would certainly be a game changer with environmental and land use issues such as public acceptance of the visual (and audible) impact of siting the necessary turbines and transmission; permitting; and the impact on avian populations rising to the forefront.

7.0 Demand-side Management Programs

This section covers OPPD's initiatives related to improving the pattern of customer energy use. These types of initiatives are often referred to as demand side management (DSM) programs. For a load serving utility, DSM consists of planning, implementing and monitoring activities designed to encourage customers to modify their levels and patterns of energy consumption. These programs generally fall into three main categories (or some combination thereof):

1. Energy efficiency 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

Effective DSM programs are considered beneficial to all customers and the utility–not just those customers participating in a specific DSM program. Successful DSM programs delay supply-side resource additions and/or optimize resource utilization through energy efficiency programs and load-shape modifications. DSM programs that increase energy efficiency also have a positive impact on the environment by lowering emissions from generation facilities. This section also discusses how OPPD verifies energy savings achieved through its DSM programs

7.1 Heat Pump Programs

OPPD has implemented both residential and commercial heat pump programs. There are two purposes for these programs. Heat pumps produce additional off-peak electrical load in the winter months optimizing power plant efficiency. In addition, peak reduction is created in the summer months through the utilization of higher efficiency heat pump equipment. The impact of the heat pump programs are accounted for in the load forecast.

Customers who install qualifying equipment receive Energy Credit Refunds and a lower winter electric rate. In addition, OPPD will randomly 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 Home Energy Audit

The intent of this program is to help residential customer's understand how they can make their home more energy efficient, safe, comfortable and durable. The program focuses on assessing the home as a system from basement to attic utilizing the latest technologies, equipment, and building science.

OPPD established the Home Energy Audit Program in the third quarter of 2006 to help customers take control of their energy use. Through traditional construction practices, old and new homes can have problems with construction in general that lead to a variety of issues including high energy consumption. OPPD promotes the Energy Audit Program conducted by contractors who are contracted by OPPD. The customer pays for this service, OPPD markets and provides oversight for the energy raters. The goal is that with this information, the homeowner will make improvements to make their homes more energy efficient, safe, comfortable and durable.

7.3 Residential Energy Star

OPPD's ENERGY STAR program helps builders meet consumers' growing demand for high quality, energy-efficient homes. By building homes that earn the ENERGY STAR qualification, area builders can join more than 5,404* trendsetting builders that have already constructed over 1,304,997* ENERGY STAR qualified homes across the country. New homes earn the ENERGY STAR by meeting rigorous energy efficiency guidelines set by the U.S. Environmental Protection Agency (EPA). Through 2011 just fewer than 2,400 new residential homes built in OPPD's service territory qualify as ENERGY STAR homes.

ENERGY STAR qualified homes are at least 15%* more energy efficient than homes built to the 2004 International Residential Code (IRC) and includes additional energy-saving features that typically make them 20-30%* more efficient than standard homes. Builders can choose from a variety of "tried and true" energy efficiency features to meet ENERGY STAR performance guidelines.

* Nation-wide statistics at the end of 2011, source: the Energy Star Homes and Department of Energy web-site.

7.4 Weatherization / LB1001Low Income Program

LB 1001 is a creation of the Energy Conservation Improvement Fund to be administered by the Department of Revenue. LB 1001 states that an eligible entity may designate state sales tax collected from customers for deposit in a subaccount. Any designation is accompanied by an equal amount of matching funds for the eligible entity. Total amount for the calendar year cannot exceed five percent of the total state sales tax collected in the prior year. A sub-account, named the Energy Conservation Improvement Fund, will hold funds distributed to the utility for energy efficiency

improvements.

OPPD will work with the Nebraska Weatherization Assistance program (NWAP) sub-grantees to give low-income residential customers an opportunity to address and change one of the causes of high energy bills by making lasting energy efficiency improvements in their homes. The homes will be weatherized by local sub-grantees and OPPD will utilize LB 1001 funds for the installation of heat pumps. Joining efforts with the NWAP allows OPPD to offer low-income residential customers effective and valuable energy efficiency services.

According to the Nebraska Low-Income and Weatherization Program, an estimated 51,000 Nebraska households are eligible for weatherization services. OPPD will assist not only with the installation of heat pumps, but a variety of functions with the weatherization program. Services such as, but not limited to, include:

- heating, ventilation, and air conditioning (HVAC) quality installation
- energy auditor training
- construction trade training on energy efficient building practices
- walk-through audit inspection services
- pre and post HALT testing and measuring
- energy bill analysis to provide measurement and validation for funder's reporting requirements

The Department of Energy statistics show that low-income families spend 16% of their income on energy, compared to 5% for median income families. The Nebraska Energy Office estimates that the average saving per dwelling will be 19% of their heating costs, leading to a decrease of default on utility bills and requiring less emergency heat assistance. With these proven statements, it is expected that OPPD low-income customers will benefit from energy efficiency improvements, and the lower heat pump winter electric rate. Customers should experience an increase in discretionary income.

7.5 School Based Education

The purpose of the school based education program is to change the energy consumption habits of students through energy awareness programs. The programs are used to motivate children to eliminate energy waste by making them more energy conscious. The awareness program will attempt to alter their attitudes and behaviors toward energy usage.

The program will target a specific audience. It will involve many energy users (students, faculty, staff and family members) and make energy- saving actions and goals as concrete as possible. This program will educate students about proactive energy reduction strategies they can do and how to do it in their daily lives.

7.6 Residential Appliance Recycling

The 2011 Residential Appliance Recycling Program will provide free pick-up of working (still operating) 10-27 cubic feet refrigerators and stand-alone freezers. In addition to the pick-up, the program provides a $35 customer rebate per appliance towards the purchase of a refrigerator/freezer Energy Star appliance

The Residential Appliance Recycling Program provides rebates to customers for the removal and environmental-responsible disposal of older, still operating, refrigerators and stand-alone freezers. The Nebraska Department of Environmental Quality supported this program with a grant of $86,000.

7.7 Energy Advisor

With over 100 years of energy related experience, OPPD's Energy Advisors provide consulting expertise on a wide variety of issues and concerns. The Energy Advisors are responsible for answering customer questions on the Energy Advisor (EA) telephone line. Upon request, the Energy Advisors provide information to the various media. Additionally, the EA researches, develops, and presents programs to civic and social groups as requested.

7.8 Energy Efficiency Education and Training

Energy Efficiency Education and Training (EEET) targets a number of segments and niches, but always with the objective of helping customers manage their use of energy in a practical and judicious manner. The EEET programs are built around a series of "Building Science" subjects relating to construction, indoor air quality, home efficiency and energy savings, lighting and heating and air conditioning. Generally, these programs follow the Department of Energy's ENERGY STAR blueprint.

7.9 Residential Time-of-Use (TOU) Rates

Time-of-use rates are rate options that present the customer with different prices based on the cost of producing and delivering electricity at various times during the year and day. There are several styles of time-of-use pricing: 1) Time-of-use rates have pre-set prices and pre-set time periods, 2) Real-Time Pricing (RTP) rates have prices that vary frequently throughout the day and year based on real-time system conditions, and 3) Critical-Peak Pricing (CPP) rates combine standard non-time differentiated rates or standard time-of-use rates with a real-time component which applies only during a few of the most critical hours of the year.

Time-of-use rates reflect the fact that electricity is more expensive to generate and deliver at certain times. As OPPD moves closer to a peak condition, the costs to provide electricity increase. There are many different styles and forms of time-of-use rates including time-of-use rates that have varying prices for pre-set time periods, real-time pricing with prices that change as often as hourly, and critical peak pricing which is

a mix of preset rates and times with a “real-time” component which activates only during very high priced hours. Time-of-use rates can be combined with a hardware solution (air conditioning control, appliance cycling, or a red-light notice) that can make it easier for residential customers to respond to the price signal.

7.10 Residential Air Conditioning Load Control

The purpose of this program is to reduce peak load requirement for residential customers. Customers volunteer to allow a device to turn off their air conditioner during peak hours in the summer. By turning on and off (cycling) air conditioning units, A/C load control can be accomplished with “minimal customer inconvenience”. To be a winning strategy for OPPD, a large number of customers need to participate allowing less time for the units to be cycled making the inconvenience factor very low.

OPPD has been testing A/C cycling the last two summers with pilot programs. The first pilot used outdoor switches attached to the A/C units to cycle the units. The second pilot used indoor thermostats to cycle the units. The results of the pilot programs are being analyzed to determine a strategy for a consumer program to start in 2011.

7.11 Green Power

OPPD offers a green power rate to customers with funds going towards supporting OPPD’s green initiatives such as renewable energy projects and environmentally based programs.

OPPD has expanded its landfill gas-to-energy plant and currently have participation purchases in place for over 135 MW of wind energy based on nameplate capacity. The power produced from these energy sources is now available for purchase by OPPD customer-owners.

Here's how it works**:**

- Subscribers to the rate sign up for a minimum of one year.
- Residential customers can participate at four levels, ranging from an additional cost of $4.50 per month to $30.00 per month.
- Commercial customers also will be able to purchase Green Power at an additional cost of about 3 cents per kilowatt-hour (kWh).

7.12 Curtailment Load Programs

OPPD Rate Schedule 467 and 467H give customers the option to participate in a mandatory curtailment program in exchange for credits for curtailed capacity and/or energy. This program has 7 accounts that provide for a load reduction of 31.9 MW.

OPPD Rate Schedule 469W provides customers the option to participate in a time of use rider in exchange for a lower demand charge with an option to buy-through on-peak

periods. This program has 3 accounts that provide for a load reduction of 7 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 25 accounts have volunteered for this rate schedule. This provides an additional 18.9 MW of voluntary load reduction.

7.13 Emergency and Standby Generator Program

OPPD has developed a unique program to partner with customers who have emergency standby generators. 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 40 accounts which results in a total load reduction of 45.6 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.

7.14 Commercial and Industrial Energy Commissioning and Optimization (ECO $_{24/7}$)

ECO $_{24/7}$ is an ongoing process, which integrates and optimizes energy system operations, minimizes energy use, improves comfort, and recommends cost-effective retrofits by applying specialized engineering approaches. The process is customized for each application, which includes commercial, industrial and central plant facilities.

ECO $_{24/7}$ improves energy system control and operation based on preexisting building and facility conditions. It is not an operational or maintenance program, nor does it simply ensure that the system is functioning as originally designed. The ECO $_{24/7}$ process typically reduces energy consumption by 25 percent (usual range is 15 to 50%), and reduces retrofit costs by up to 15 percent (usual range is 5 – 20%). OPPD has differentiated itself from other utilities by making ECO $_{24/7}$ available to our customers which embodies our commitment as their energy partner.

7.15 Innovative Energy Efficiency Project (IEEP) Pilot

The objective of this pilot is to provide commercial and industrial (C&I) customers financial incentives to permanently reduce their energy and demand usage through innovative energy efficient projects. In order to qualify, projects must lower annual energy consumption by 10% or more, be performed on buildings in excess of 30,000 square ft or have an OPPD bill through one meter of $30,000 or greater during the calendar year. An IEEP Trade Ally group patterned after OPPD's Lighting Trade Ally

group has been initiated and currently includes 5 providers. The recruitment includes annual training and completing and acceptance of a request for information. IEEP projects may include the following:

- ECO 24/7 project and other similar building energy efficiency projects
- Energy Management Systems upgrade and optimization
- Chiller/boiler plant upgrades, retro-commissioning, or optimizations
- Air distribution system retrofit and control upgrade/optimization
- Rooftop Units retrofit and optimization
- Heat pumps retrofit and optimization
- Motor upgrades
- Variable frequency drivers (VFDs) and (or) high efficiency motors
- Air compressor
- Refrigerant systems

The pilot program will pay customers two incentives one for an initial Energy Study and another for project results as shown in peak kW reduction. The Energy Study incentive will be for up to 50% of the total cost with a $10,000 maximum. This incentive will only be paid to customers who move forward with project implementation and have received preapproval from OPPD. The second incentive will be paid based on the OPPD measured and validated results after the project and will be in the amount of $400 per kW reduction. The rebates will be offered for a limited time and only while the budgeted funds are available. The project will not qualify for any other load curtailment program/rebate. There is a limit of one incentive per building per year.

7.16 Prescriptive Rebates

The purpose of this prescriptive pilot program is to promote the installation and use of high-efficiency equipment in C&I settings by providing predetermined rebates based on energy efficiency and the impact to OPPD.

When a customer is replacing or installing new equipment, first costs are always considered. Many commercial tenants have fairly short term leases so when equipment fails or buildings are built lowest first cost wins. A rebate lowering the first cost will make energy efficiency more attractive.

A prescriptive lighting systems rebate increases the implementation rate of high-efficiency commercial and industrial lighting alternatives. This rebate program resulted in both a reduction in energy usage (kWh) and lower peak demands (kW).

A prescriptive motor rebate pilot program is recommended in the future to increase the implementation rate of high efficiency motors. The high efficiency motor will result in both a reduction in energy use and lower peak demand.

7.17 Commercial and Industrial Energy Star

The objectives of this program are to encourage innovative energy efficiency measures in commercial and industrial (C&I) buildings and to assist our customers in the identification/creation of ENERGY STAR buildings or attaining ENERGY STAR Leader Status.

The first step required for a building to receive ENERGY STAR status is obtaining a Portfolio Manager rating of 75 or above. Once that score is achieved, OPPD will work with the customer on the additional review, engineering and application needed to attain certification as an ENERGY STAR building. For scores less than 75, OPPD employees will work with the customer to make energy efficiency plans and installation of energy conservation measures.

OPPD has shown a commitment to energy efficiency by attaining ENERGY STAR Leader status in July of 2011. This was done by lowering our usage by over 10% in OPPDs portfolio of buildings that qualify to be included in the program. OPPDs intent is to engage customers to also become ENERGY STAR Leaders and to have ENERGY STAR Buildings. According to the ENERGY STAR program, buildings attaining ENERGY STAR status use 30% less energy than those not qualified.

7.18 LED Streetlight Pilot Program

OPPD worked with the City of Omaha to determine if a new street light technology lives up to advertised energy savings and safety. The OPPD Street Light Pilot Project evaluated the performance of six LED (light emitting diode) street lights installed from 45th to 46th on Woolworth Street. The test program represents just a small sample of the 96,000 street lights in OPPD's 13-county service territory. Similar tests may be conducted in one or two other areas of the city. This test program is part of OPPD's sustainability effort to use resources as wisely as possible. Producers of LED streetlights claim the product with require less maintenance due to the extended life cycle and are more energy efficient. A conventional high pressure sodium light bulb draws about 117 watts, while an LED uses about half as much. OPPD estimates 82 million kilowatt-hours of electricity will be used next year to light streets in its territory.

7.19 Plug-in Electric Vehicles (EV)

Several major automobile manufactures have introduced or have plans to introduce plug-in electric vehicles referred to herein as EV. An EV like the Chevrolet Volt also contains a gasoline engine which is used as a back-up charging source when a plug in charge is unavailable. This shift in technology represents a major impact to electric utilities which are the main source of “fuel” for these cars in the future. OPPD is testing new cars that use advanced battery technology as an energy- supplement to its gasoline-powered engine. Electric utilities need to position themselves to best adapt to this potential growing load to their systems. The potential size of this market is undetermined as consumer decisions are difficult to predict.

OPPD is preparing for expanding consumer use of EVs in the OPPD service territory. In July 2010, OPPD initiated the Electric Vehicle Readiness Project to support the creation of an EV market in the OPPD service territory and develop a strategic plan for the successful integration of EVs with OPPD's power supply infrastructure. Throughout the project's two-year time-line, OPPD will engage with stakeholders ranging from vehicle vendors and property owners to government entities. The project has four task forces that will work with vehicle vendors, property owners and additional stakeholders. The project will develop programs to support EV vendors and EV owners.

OPPD recently conducted an analysis of all the steps required for a customer to achieve "plug-in-readiness" if they elect to purchase an EV. The emphasis is to make the process simple and convenient for the customer by utilizing partnerships within the community.

One of the challenges of preparing for the arrival of EV is the difficulty in predicting how fast the market will grow and how large it will become. The Electric Power Research Institute (EPRI) estimates that the current power grid can handle many tens of millions of cars plugging in at off-peak hours before capacity issues become a concern. OPPD's existing grid infrastructure is deemed robust enough to easily handle early market penetrations of EVs. OPPD will closely evaluate impacts of EV penetration during these early years to plan for potential larger penetrations. OPPD will monitor customer interest in EVs to better anticipate the degree of growth.

With the expected EV market OPPD has been working for some time to become a key source of information for local consumers interested in purchasing an EV. In early 2011 the district launched a new website to provide the most current EV information for those interested; information ranging from charging options and environmental benefits to the latest incentives and a readiness checklist for potential purchasers. The website is OPPD.com/EV.

OPPD is one of more than 40 utilities across North America that has received and will test drive a Chevrolet Volt Extended Range Electric Vehicle through EPRI and General Motors. This project, will gather information regarding such things as driving behavior and charging information while giving utilities more hands-on experience with this type of EV. The overall objective of the project is to prepare the utility industry for adoption of plug-in EVs and to provide the technological foundation for integration of the vehicles into utility metering and other grid systems. The program is made possible with a grant of $30.5 million from the Transportation Electrification Initiative administered by the U.S. Department of Energy through the American Recovery and Reinvestment Act.

7.20 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 examine energy consumption behaviors 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 our customer-owners.

7.21 2010 Commercial Heat Pump Program

OPPD offers a full spectrum of turn-key geothermal and water-source heat pump design solutions for commercial customers. We also provide a one-time incentive of $50 per nominal ton for the installation of the following types of electric heat pump HVAC systems in commercial and industrial facilities:

- Air-Source Heat Pumps with A Minimum SEER of 13.0
- Water-Source Heat Pumps
- Geothermal Heat Pumps

7.22 OPPD's 2010 Digi RTU Optimizer Pilot Program

In 2010 OPPD launched its Digi RTU Optimizer Pilot program and expanded it in 2011. This pilot has gained national attention through articles by the APPA and by presentations at various national conferences including the AESP's 21st National Conference & Expo, ESource's Annual Forum, the ACEEE Summer Study and the APPA Customer Connections Conference. The pilot also received grant funding through the APPA due to the nature of its innovative technology and ultimately received the APPA's, DEED Energy Innovator Award for 2011 (one of only two nationally).

The Digi-RTU Optimizer technology, utilizes one VFD to modulate both the fan and compressor speed of the RTU. It consists of a variable frequency drive (VFD), an optimizer controller, and a temperature sensor. The speed of both compressor and fan is modulated based on actual cooling load to maintain the space temperature required. The costs are kept reasonable because one drive serves to impact the functionality of two components. Results show an energy reduction ranging from 28% to 68% with the average being 47%, an average reduction in demand of 40% and reduction in system cycling of up to 70% all while maintaining occupant comfort.

7.23 DSM Program Options Modeled

A comprehensive list of DSM programs was selected after a previous review of over 200 successful DSM programs through a DSM potential study completed by a team which included OPPD, University of Nebraska-Omaha, Quantec and Summit Blue. Programs were reviewed by considering technical, economic and adaptability factors. These programs can be characterized as peak clipping, load shifting, valley filling or some combination thereof. Following the review of the programs, the 2011 IRP focused on programs that provide desirable efficiency and load-modifying effects. In addition,

DSM tests were utilized for OPPD programs. It is the goal to continue analyzing programs as data becomes available.

OPPD reviews the results of the industry standard DSM tests. The purpose of these tests is to determine the benefit/cost ratio over the life of the energy efficiency measure from different perspectives; with regard to the ratepayers, the utility, societal and total costs. Inputs to the tests include:

- utility benefits (avoided costs) based on demand and energy savings
- customer incremental and installed measure costs
- utility lost revenues and customer energy cost savings
- program administrative costs and customer incentives

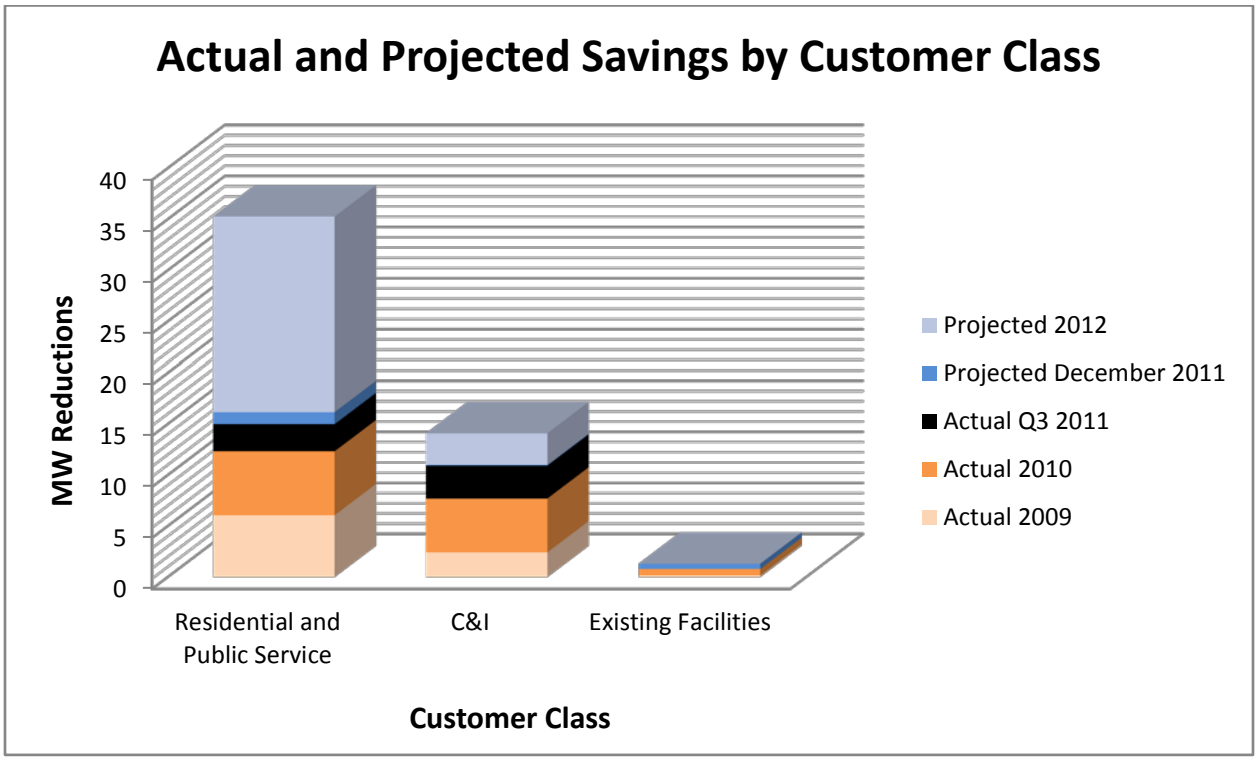
The TRC test is the most commonly used benchmark to determine which DSM programs should be implemented, although this may vary per utility. The TRC is a total cost perspective. A SCT test is a societal evaluation and is the TRC test with an environmental cost adder. Additionally a Utility Cost Test was performed which compares only the utility costs to the avoided costs. The test is used to determine whether a demand side program is less costly from the utility's perspective than a supply side option. The programs studied and their impact on system demand if fully running are shown in Table 13.

Table 13 - Key Customer Programs Evaluated Per Industry DSM Tests
(Load at Customer Level)

Program	Actual and Forecasted Demand Reduction (MW)	TRC Test Value	SCT Test Value	UCT TEST Value
C&I: Prescriptive Lighting Program	9	1.304	1.788	5.171
C&I: Innovative Energy Efficiency Projects (IEEP)	5	1.156	1.607	2.065
Residential: Appliance Recycling Program	2	0.875	1.167	0.701
Residential: High Efficiency AC Program	1	0.211	0.273	0.550
Residential: School Based Education	1	0.798	0.978	0.399
Residential: Energy Star Home Energy Certification	1	0.007	0.007	0.419
Residential: AC Load Control	15	2.066	2.066	.833

The total expected MW savings of the programs OPPD is implementing classified per customer class are shown in Table 14. The bar plot show the cumulative impact of program implementation from 2009 through 2012. The existing facility classification represents OPPD owned facilities.

Table 14 – Customer Program Cumulative MW Savings, Actual and Projected by Customer Class



7.24 Demand Reductions Impact on the OPPD 15-Year Plan

Table 15 shows the impacts of various levels of demand reductions on the OPPD 15 Year Plan. The base case which is the basis of the OPPD 15 Year Plan includes demand reductions to the base load forecast of 50 MW in 2012 and sustaining. This demand reduction is in addition to current demand reductions achieved through existing curtailable rate agreements. All cases shown include the wind resource additions to achieve the OPPD 10% Renewable Energy Goal which are shown in the right-most column.

An expansion plan without demand reductions would require a combustion turbine (CT) in 2019 instead of a CT in 2021 and another CT in 2023 instead of 2024. An entirely new combined cycle project would be needed in 2026. Three other demand reduction cases are shown. Each would achieve a 50, 75 or 100 MW demand reduction by 2014 and sustain for future years. In these cases the annual net system requirements of the base load forecast are adjusted to achieve an annual load factor of fifty-four percent (or a little higher) in years beyond 2014. The base load forecast has a load factor a little under fifty-four percent.

The 50 MW demand reduction by 2014 case achieves the same demand reduction as

the base case but 2 years later and with extra energy conservation. The resulting expansion plan is the same as the OPPD 15 Year Plan. The 75 MW demand reduction case delays the CT one year, placing it in 2022. The 100 MW demand reduction case is similar to the 75 MW demand reduction case in that it requires the CT in 2022 as well. In the 75 MW and 100 MW reduction cases the next resource after the CT is natural gas fueled combined cycle. In the 75 MW case an all new combined cycle is required in 2025. Slightly different, the 100 MW case chooses the Cass County conversion in 2024 as the most economic resource. In all the cases, single year capacity purchase requirements are needed in select years and are shown according to their size of either 50 or 100 MW capacity (e.g. Prch 50 and Prch 100).

Table 15 – DSM Reduction Effects on Expansion Plan

Year	OPPD 15 Year Plan, Base Case	No DSM Reduction	50 MW Demand Reduction by 2014	75 MW Demand Reduction by 2014	100 MW Demand Reduction by 2014	Renw Goal Additions, All Cases
2012						Existing
2013						Wind ~212
2014						
2015						
2016						Wind – 20
2017						
2018		Prch 50				Wind – 80
2019	Prch 50	CT	Prch 50			
2020	Prch 50		Prch 50	Prch 50	Prch 50	Wind – 80
2021	CT	Prch 50	CT	Prch 100	Prch 100	
2022	Prch 50	Prch 100	Prch 50	CT	CT	
2023	Prch 100	CT	Prch 100	Prch 50	Prch 50	
2024	CT	Prch 50	CT	Prch 100	CC Conv	
2025	Prch 50	Prch 100	Prch 50	CC		
2026	Prch 100	CC	Prch 100		Prch 50	

7.25 Measurement and Verification

One of the goals of the DSM programs is to reduce demand usage to defer future generation; it is vital that the demand reductions are reported accurately. The primary purpose of measurement and verification is to establish good practices that will ensure accurate information about the kW and kWh savings from DSM programs. For measurement and verification purposes, OPPD adheres to the International Performance Measurement and Verification Protocol (IPMVP).

Although each program is unique, the way savings are reported must be consistent in order to fairly evaluate the programs and report the savings, otherwise, the results will not be compared equally. This would result in inaccurate information being reported for use in OPPD's decision making process about the timing for future generation needs. Data may be collected periodically based on the program design. As part of this process, baselines are established so results obtained by each program may be measured. When applicable, it may be necessary to make adjustments to base year data such as weather, occupants, added space, equipment changes, etc. however, this is determined on a program by program basis and is evaluated once the baseline is established.

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

Given continued projections for lower OPPD load growth when compared to projections established before the economic downturn in 2008, the 2011 IRP OPPD 15 Year Plan doesn't require new, dispatchable generation until 2021. An OPPD 10% Renewable Energy Goal requires around 400 MW of wind by nameplate rating which will deliver 10% of OPPD's retail energy needs by 2020. The 2011 IRP recommended additions over the next 15 years are shown in Table 16.

Table 16 – OPPD 15 Year Plan

Year	Resource Addition	Reason
By 2013	Wind Turbines, 212 MW Nameplate Rating, cumulative installed for OPPD use	Renw Goal
2016	Wind Turbines, 20 MW Nameplate Rating	Renw Goal
2017	75 MW, FC HP Turbine Power Uprate – Project Completed during prior Outages	Load Growth
2018	Wind Turbines, 80 MW Nameplate Rating	Renw Goal
2020	Wind Turbines, 80 MW Nameplate Rating	Renw Goal
2019, 2020	Single Year Peaking Capacity Purchases	Load Growth
2021	Combustion Turbine, 160 MW	Load Growth
2024	Combustion Turbine, 160 MW	Load Growth

The wind facility additions are assumed to operate at 40% capacity factors. Implementation of a state or federal RPS would undoubtedly set renewable requirements higher than 10%.

Other Purchase and Sales

OPPD has a firm capacity purchase contract with the Western Area Power Administration (WAPA). The current contract is through year 2020. Under WAPA's 2021 Power Marketing Initiative, WAPA will possibly extend the contract term by 30

years with the extension beginning in 2021 and running through 2050. OPPD also provides firm wholesale service to Boys Town, Elk Creek, Greenwood, Syracuse and Tecumseh. All of these transactions are shown in Attachments 1 and 2.

8.2 Unit Participation Option

On May 1, 2009 Nebraska City Unit 2 was commissioned and the seven long-term participants began to receive energy from the unit. Nebraska City Unit 2 has a rating of 684.6 MW using coal.

A third coal fueled unit at Nebraska City Station is provided as an option in the Strategist model. This third unit is not selected as part of the OPPD 15 Year Plan. Nor is it selected in any year through 2041 in the base case assumptions used in the OPPD 15 Year Plan. Given the quantities of CO_2 allowances OPPD would receive under legislative proposals and their projected costs, a pulverized coal resource is not the most economic choice. A low CO_2 emitting coal resource is dependent on large-scale carbon capture technology and incumbent uncertainty on its practicality, expense and impact on station efficiency. Selecting a truly low CO_2 coal resource within the next 15 years may be nothing more than a wishful placeholder. The coal unit option provides 300 MW of capacity to serve OPPD retail customers with the remaining MW to serve other utilities. This joint arrangement takes advantage of the economies of scale rather than building a 300 MW unit just for OPPD use.

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 an 800 MW 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 with the exception of Nebraska City Unit 2 have been in service for more than 25 years. In the 2011 IRP, it is assumed for study purposes only, that Nebraska City and North Omaha units will be retired after 75 years. However, future legislated regulations on CO_2 emissions as well as enactment of rules by the EPA, including CO_2, under the Clean Air Act Amendments may change the retirement dates of the oldest coal units due to regulatory driven economic considerations. The commercial operation dates and the base case studied retirement years for OPPD baseload units are shown in Table 17.

Table 17 – Age of Existing Baseload Units

Baseload Unit	Commercial Operation Year	Current Age (Years)	Studied Retirement Year	2011 Rating (MW)
North Omaha 1	1954	57	2029	79.3
North Omaha 2	1957	54	2032	107.7
North Omaha 3	1959	52	2034	108.4
North Omaha 4	1963	48	2038	138.4
North Omaha 5	1968	43	2043	204.4
Ft Calhoun	1973	38	2033	478.6
Nebraska City 1	1979	32	2054	651.5

Based on the current assumptions, Ft Calhoun, and North Omaha Units 1, 2, 3 and 4 will be retired within the 30-year study period of the 2011 IRP (2012-2041).

With proper operating and maintenance practices, 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.

Long-term engineering studies are typically required to confidently predict: 1) remaining life; and 2) if expenditures above and beyond those typically expected are needed for continued operation. Studies of this type are increasingly needed as units reach a typical retirement age and resource planning horizons extend into this timeframe. OPPD is currently undertaking specific detailed studies on regulatory assessment of OPPD's generation resources. The results of this assessment will be completed in 2012.

As stated above, a main driver that could cause older generating units to be retired is the compliance cost of environmental regulations. The current set of rules the EPA is promulgating relating to air and water emissions and solid waste disposal have potential to shut down older plants as it will not be cost effective to make the upgrades necessary to comply. For older units, installing expensive environmental control equipment will be cost prohibitive relative to the value of keeping the unit in service. The emphasis of EPA regulations on continuous emissions especially for mercury and air toxins eliminates the option to utilize an older coal unit less hours in a year. If regulations addressed only annual limits for emissions, for example NO_X, SO_2 and CO_2, utilizing the

unit less would be a compliance option. OPPD has the option to fuel the oldest coal units (located at North Omaha Station) on natural gas which will allow these units to meet continuous emission rules without installing multi-pollutant controls. 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 and tightening limits on SO_2 and NO_X, 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 installation of enough wind to provide 10% of OPPD's retail needs from renewable sources will further OPPD's fuel diversity and lessen the reliance on fossil fuel. The natural gas fueled combined cycle generation option 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.

8.5 Reliability

Nebraska City Unit 2 being a subcritical conventional pulverized coal unit is expected to be highly reliable going forward. Reliability was a major factor in choosing this technology to meet OPPD growing baseload requirements as of 2009. Coal is the fuel for approximately 65-70% of OPPD energy production. 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 were 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.

During the summer 2011 OPPD's three baseload generating stations were threatened under historic, prolonged flooding of the Missouri River. Nebraska City Station and North Omaha Station remained operational through auxiliary flood protection measures and employee diligence. The Fort Calhoun Station nuclear station, already in a refueling outage, remained in safe shutdown as critical assets remained protected.

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 continues to grow but remains small enough that its impact on dispatch is manageable. 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. OPPD staff participates in routine training on power system restoration. Required employees are all NERC certified operators and accomplish the necessary training to retain certification. OPPD like all electric utilities (and the various NERC defined roles and functions contained within the corporate structure) have been audited on NERC standards by their regional Reliability Entity.

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 in a given year during the 2012 through 2026 time period. Nonetheless, these technologies are not considered the most economically feasible options for OPPD. Energy storage is considered. 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 and construction costs are very site specific. Several new battery chemistries are being considered. However, none of them is at a high-level of development for utility scale applications and only limited test installations are in service at this time. Compressed air energy storage (CAES) has received study in some locations, even in the Midwest U.S. A proposed CAES project in Iowa did not come to fruition. Geologic dome structures in western Nebraska are being considered for a potential CAES project by a Midwest utility – this project is partly contingent on the economic value of storage within regional electricity markets.

8.9 Suboptimal Future Resource Options

The 2011 IRP, Strategist optimization evaluates 30 years into the future to develop the OPPD 15 Year Plan. Table 18 shows several suboptimal resource options. Three of the options shown demonstrate timing impacts of the Cass County conversion to combined cycle operation. The Cass County conversion is not in the OPPD 15 Year Plan but was in the 15 Year Plan of the 2010 IRP. The cases shown in Table 18 include different conversion years at Cass County, 2019, 2020 and 2021. As can be seen in Table 18 the Cass County conversion is a fairly costly alternative plan. If the Cass County conversion is forced in 2022 or in years after, the resulting expansion plan becomes even more costly as then, an all-new combined cycle is slotted in 2021 in these cases. The additional 208 MW of capacity the conversion provides is not ultimately required until 2021. A suboptimal plan that includes forcing an all-new combined cycle has lower costs than forcing the Cass County conversion. The all-new combined cycle would be placed at the Cass Station location. In this case the existing Units 1 and 2 at Cass would remain as simple cycle combustion turbines (CT). The lowest cost year for the combined cycle is 2024 with a NPV cost of $27 million greater than the OPPD 15 Year Plan. Requiring an IGCC unit to be installed in year 2020 costs 7.8% more than the OPPD 15 Year Plan. The advanced nuclear and IGCC options are discussed in Section 6.

Table 18 – Suboptimal Options Analysis

Description	Additional Capacity (MW)	Year of Baseload /Interm Unit	NPV 2012 m$'s	Change from 15 Year Plan	Change from 15 Year Plan
OPPD 15 Year Plan	CT-160	2021	$19,199	$0	0%
Cass Conv 2019	208	2019	$19,696	$497	2.6%
Cass Conv 2020	208	2020	$19,684	$485	2.5%
Cass Conv 2021	208	2021	$19,673	$474	2.5%
New CC 2019	530	2019	$19,319	$120	0.6%
New CC 2020	530	2020	$19,289	$90	0.5%
New CC 2021	530	2021	$19,260	$61	0.3%
New CC 2022	530	2022	$19,280	$81	0.4%
New CC 2023	530	2023	$19,252	$53	0.3%
New CC 2024	530	2024	$19,226	$27	0.1%
IGCC	300	2021	$21,318	$2119	11.0%

Attachment 18 shows the detailed expansion plan of the OPPD 15 Year Plan plus select extra cases out to year 2036 as determined in the study model.

8.10 Ft. Calhoun Power Uprate, Project Timing Analysis

The project details of Ft. Calhoun Power Uprate are discussed in Section 6. This uprate in thermal input along with a new high pressure turbine accomplishes an increase in generation capability of 79 MW in all months except for July and August, where the increase will be 75 MW.

The Ft. Calhoun extended power uprate has been part of the lowest cost expansion plan for many prior years of annual IRP analysis. Prior IRPs have evaluated project costs in the light of latest assumptions. The economics of the project is strengthened as cost on carbon emissions is implied in future years. However, the magnitude of projected carbon taxes has moderated.

The power uprate had been targeted to be completed in preparation for the 2013

summer season. During the summer of 2011 it was decided to delay the power uprate as the staff at Fort Calhoun needed to give full focus to recovering from the flooding of the Missouri River and increased regulatory oversight.

Summary of power uprate scenario analysis are shown in Table 19. On a 30 year NPV basis completing the power uprate in 2017 was the most economic option under the base case carbon assumption as well as the zero CO_2 cost case. Completing the power uprate by 2019 is also less in NPV than not performing the uprate at all. If the power uprate is not performed then the requirement for the combustion turbine in 2021 is moved up two years, to 2019.

Detailed expansion plans for a select number of the cases are shown in Attachment 18.

Table 19 – Ft Calhoun Power Uprate Scenarios

	No Power Uprate	**Power Uprate in 2017**	**Power Uprate in 2019**
Sensitivity	(Values are NPV in 1,000,000 $'s)		
Base Carbon Allowance Cost	$19,492	$19,199	$19,379
No Carbon Cost, Carbon Allowance $0	$15,380	$15,233	$15,333
High Estimate, Project Capital Expenditure	$19,492	$19,211	n/a
High Cap Ex, $0 Carbon	$15,380	$15,245	n/a
Comments:		Lowest Cost Scenario, All Sensitivities	2nd Lowest Cost Scenario

8.11 Summary and Conclusion

The OPPD 15 Year Plan includes the Ft Calhoun power uprate to be completed by 2017. Beyond 2017, a capacity resource is not needed until 2021. This resource is an additional simple cycle combustion turbine at Cass County Station. By 2024 another simple cycle combustion turbine (CT) sized at 160 MW is needed.

Given the load growth forecasts of 1.8 percent per year for demand and 1.8 percent for net system requirements, fuel cost projections, capital construction costs and emission costs; any need for new baseload construction has been pushed out beyond the next 15 years. With lower natural gas forecasts than a year ago, the best way to meet OPPD's

load growth is by adding combustion turbines in 2021 and 2024. In the 2010 IRP the recommended resource in 2021 was the conversion of Cass County Station Units 1 and 2 to combined cycle. The analysis of forcing Cass conversion in 2021 (under base load forecast) rather than building simple cycle combustion turbines in 2021 and 2024 increases the NPV of the Strategist results by 2.5%.

A key uncertainty going forward in developing a resource plan is pending environmental regulations. Placing a cost on CO_2 emissions from fossil fuel consumption hinders consideration of any new coal fueled generation unless some amount of carbon capture technology is assumed. It will take a herculean effort by the utility industry to implement large scale carbon capture technology in the next 10 to 15 years. Implementation of stricter environmental regulation will accelerate plans to retire existing coal generation. Changing market directions also will dictate decisions. One such market is natural gas. Only a few years ago U.S. domestic gas was deemed to be a scarce resource, now there is a projected adequate supply going forward with additional shale gas. As wind powered generation grows in the Midwest, a quick responding, dispatchable resources such as gas turbines, may become increasingly important to have available to system operators. Baseload generation's utilization will be reduced.

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 2011 IRP determine the impact on key data assumptions on the economic viability of the resource additions in the OPPD 15 Year Plan. Table 20 shows select sensitivities of the OPPD 15 Year Plan to OPPD's load growth, wholesale market pricing, an RPS and a zero carbon tax. The sensitivity cases shown in Table 20 and additional sensitivity cases are shown in Attachment 16.

Generally with the addition of Nebraska City Unit 2 in 2009 and with lower load forecast projections, OPPD is situated well with generation resources during the 2012 – 2026, 15 year period. The addition of wind energy to meet the 10% Renewable Energy Goal along with customer demand reductions and efficiency gains further negate what otherwise would be fuller utilization of dispatchable generation. Along with the Ft Calhoun power uprate the only other resource additions required in the OPPD 15 Year Plan are two simple cycle combustion turbines in the years 2021 and 2024.

The option to convert the two existing gas turbines at Cass County Station to combined cycle is allowed in years 2016 – 2025 in the IRP Strategist analysis. The Cass conversion option is not allowed beyond 2025 due to consideration of remaining life of the existing combustion turbines, they will be 22 years old in 2025. In the 2011 IRP OPPD 15 Year Plan this conversion option is not selected. There are select sensitivities in which the Cass conversion is chosen. These include a high load forecast growth rate of approximately 2.5%/year. In this sensitivity the Cass conversion is needed in 2025. A sensitivity of very high natural gas prices requires the Cass Conversion in 2024. Natural gas forecasts have done an about-face in the last 2 years. A very high cost natural gas sensitivity case certainly isn't deemed as likely as it was a few years ago. The base case carbon tax assumption in the 2011 IRP is reduced from the 2010 IRP. In the 2011 IRP a high carbon tax scenario does require a Cass conversion in 2024. The lower base case carbon tax assumption in the 2011 IRP reflects the lower near-term expectation of Congress passing greenhouse gas legislation.

Another generation resource which is an option in the IRP analysis is the installation of an all-new combined cycle. In this case the two existing combustion turbines, Unit 1 and 2 at Cass County Station, would remain in service as-is. Also the all-new combined cycle can be put in service before or after any further CTs are added at Cass County Station. In the base case analysis a new combined cycle is required in 2027. None of the sensitivities studied moves up the combined cycle into the OPPD 15 Year Plan.

The Ft Calhoun power uprate has been part of the OPPD 15 Year Plan in many prior OPPD IRPs. It remains economical. The flood event of 2011 and subsequent station restart effort postponed the feasibility of completing the power uprate by 2013. The power uprate is now slotted to be available in 2017. If the power uprate project costs can be maintained at prior assumed levels, it is economic to have it in place as of 2017 under all sensitivities. Among these sensitivities are both a low and high growth load forecast, varying wholesale market prices, a forward zero CO_2 tax, fossil fuel price variances, renewable energy requirements and others.

As discussed in Section 8, the economics of postponement of the uprate to 2019 or cancelling the uprate are analyzed. The postponement to 2019 remains a consideration. The 15 year expansion plans are nearly the same between the 2017 and 2019 power uprate cases. The combustion turbine in 2021 remains the first new resource required in either case. If the uprate is postponed until 2019, any necessary capacity needs in 2018 can be met by a one-year capacity purchase from the market. The 2019 case's major detraction is that with a retirement of Ft Calhoun in 2033, the 2019 uprate completion loses 2 years of benefit to the 2017 base case. Also in consideration is comparing capital that has been spent on the project to capital expenditures that could be delayed beyond 2017 if the uprate was postponed until 2019. The power uprate economics are sound, though it should be noted that some amount of analyzed benefit from the project is lost as any direct costs on utility carbon emissions are delayed further beyond 2017.

The installation of a simple cycle combustion turbine (CT) is recommended for 2021 and an additional CT in 2024 in the OPPD 15 Year Plan. A CT can be added at comparably low capital costs and short lead times versus other technology options.

A lower load growth forecast sensitivity delays the installation of the first CT until 2027. A higher load growth forecast requires a CT in 2021 and 2024 (which matches the OPPD 15 Year Plan) and then puts the Cass Station combined cycle conversion in 2025. A 15 year study period (rather than 30 year) installs the Cass combined cycle conversion in year 2021. High and low natural gas sensitivities do not change the requirement for a CT in 2021, but a very high gas cost replaces the 2024 CT with the alternate Cass conversion option.

As shown in Section 8, forcing the Cass conversion into the plan in 2021 does raise the 30 year NPV by 2.5%. Future IRPs will continue to examine the economics of a Cass conversion option. Through the past 3 years the Cass conversion has been in and out of the OPPD 15 Year Plan. In the 2009 IRP it was not part of the plan. In the 2010 IRP it was part of the plan. Now in the 2011 IRP it is not. Transmission system addition costs are a consideration at Cass County Station. Currently, available transmission is mostly in place to support the addition of either one CT or the Cass conversion. The next addition beyond either of these options in the form of a CT in 2024 (or other) will require an extensive upgrade to the existing transmission system from the station.

In a sensitivity where the carbon tax is one-half the base assumption, the OPPD 15 Year Plan does not change. The same is true with a zero carbon tax sensitivity. However, in both these sensitivities the next baseload capacity addition, which is beyond 15 years, will be a pulverized coal unit (Nebraska City Unit 3) in 2028 and is a 660 MW unit with half the output being sold to participants.

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 the degree of change necessary in existing forecasts to alter the resources specified in the OPPD 15 Year Plan.

Table 20 – Load Growth, Wholesale Market, RPS and Carbon Sensitivity Case Analysis

Case #	Description	Combustion Turbine — Year or No	NPV 2010 m$'s	Change from Benchmark	Change from Bench-mark
B01	OPPD 15 Year Plan	2021	$19,199	$0	n/a
B02-S08L	Low Load Growth Forecast 1.0%	No	$14,213	$(4,986)	(26.0)%
B02-S08H	High Load Growth Forecast 2.5%	2021	$23,113	$3,914	20.4%
B02-S12L	40% Reduction in Wholesale Prices	2021	$18,215	$(984)	(5.1)%
B04-S09L	20% Reduction in Wholesale Prices	2021	$18,958	$(241)	(1.3)%
B02-S9H	20% Increase in Wholesale Prices	2021	$19,016	$(183)	(1.0)%
B02-E3	No Interchange Sales	2021	$19,451	$252	1.3%
B02-E1	No Interchange Purchases	2021	$19,522	$323	1.7%
B02-E2	No Interchange Sales or Purchases	2021	$19,802	$603	3.1%
B05-15	15% RPS	2021	$19,102	$(97)	(0.5)%
B05-20	20% RPS	2021	$19,029	$(170)	(0.9)%
B06-C01N	No Carbon Tax	2021	$15,380	$(3,819)	(19.9)%

9.2 Benchmark Sensitivity Cases for Carbon Pricing

In the 2011 IRP, sensitivity analysis was completed to determine the impact that carbon costs would have on the benchmark, baseload generation resource.

As mentioned above, a zero and low carbon tax scenario will not impact the OPPD 15 Year Plan. The Ft Calhoun power uprate is economical in a zero carbon scenario as shown in Section 8.

The low, base and high carbon tax scenarios all begin a carbon tax starting in year 2015. Since the 111th U.S. Congress did not enact a climate change bill structured on the Waxman-Markey House of Representatives bill, a delay in imposing a carbon tax until 2015 is appropriate. The 2011 IRP assumes a CO_2 tax of $14/ton beginning in 2015 and increasing steadily until to $67/ton is reached in 2035 (real 2012$'s). The 2010 IRP assumed a CO_2 tax of $22.2/ton beginning in 2015 increasing steadily until $63.1/ton is reached in 2034 (real 2010$'s).

The 2011 IRP base case projections for a carbon tax are lower in the early years compared to the 2010 IRP. This ends a trend over the past 5 years of ever growing projections in the cost of a carbon tax. With no federal legislation with regards to climate change on the forefront of congress' agenda, the observation could be made that the magnitude of a carbon tax assumption reflects the probability of legislation being enacted. See Table 21 for the carbon tax assumptions of the base case and other sensitivities.

Table 21 – Carbon Pricing
($/Ton of CO_2 in 2012$'s,)

	No Carbon Cost	Low Case	Base Case	High Case
2012 – 14	0	0	0	0
2015	0	7.00	14.00	21.00
2016	0	7.00	14.00	21.00
2017	0	7.50	15.00	22.50
2018	0	7.50	15.00	22.50
2019	0	8.00	16.00	24.00
2020	0	8.00	16.00	24.00
2021	0	8.50	17.00	25.50
2022	0	8.50	17.00	25.50
2023	0	9.00	18.00	27.00
2024	0	9.00	18.00	27.00
2025	0	10.50	22.00	31.50
2026	0	12.00	25.00	36.00
By 2035, Increases to:	0	32.50	67.00	97.50

9.3 Wind Energy Sensitivity Cases

The OPPD 2011 IRP uses additional sensitivity cases to demonstrate the economic viability of wind energy to variations in assumptions. OPPD will install approximately 400 MW of wind nameplate capacity by 2020 to meet the OPPD 10% Renewable Energy Goal. The following is a discussion of some of the cases as listed in Attachment 17.

OPPD's wind portfolio of wind facilities is expected to be near 212 MW by the end of 2012. This includes existing wind facilities of Ainsworth, Elkhorn Ridge Flat Water and Petersburg along with planned purchases from Crofton Bluffs and Broken Bow. The 2011 IRP includes the addition of further wind to meet the 10% OPPD Renewable Energy Goal. This regime of adding 80 MW wind farms 2018 and 2020 and a 20 MW farm in 2016 is fixed in these years and is not allowed to be altered in the suboptimal plans in Attachment 15 and the sensitivities of Attachment 16. However in Attachment 17, select sensitivities are shown in which the fixed wind additions for the 10% renewable energy requirement are changed to meet a 15% and 20% renewable requirement. One case removes any future wind beyond the year 2012. Another set of cases puts the 80 MW farms in 2013, 2014 and 2015 at lower costs than used in the base case for wind energy. This schedule allows OPPD to reach the 10% OPPD Renewable Energy Goal by the end of 2015. In 2010 and the world-wide demand for new, utility scale wind energy facilities softened and prices being offered by wind developers have decreased. This is expected to be a limited term price-taking opportunity and wind prices will rise as the economy begins to grow again. Also many utilities in states with stepped- in, mandated RPS, will again need to reinvigorate pursuit of their legislated requirements which will drive up wind pricing.

The base case cost assumption for wind energy is $55.0/MWh where all costs related to wind energy are recovered through this rate. At $55.0/MWh and under the base case carbon tax, a 10% renewable requirement has a lower net present value than installing no wind at all after 2012. Increasing the wind to meet a 15% renewable goal or even a 20% renewable goal leads to an even slightly lower NPV. Contrarily, in the 2010 IRP when the base cost of wind was $62.7/MWh, installing 15% or 20% wind was more expensive in NPV than a 10% renewable goal.

Under the zero carbon tax scenario it costs more in NPV to meet the 10%, 15% and 20% renewable goals than installing no further wind after 2012. The 2011 IRP base case carbon tax assumption with wind priced at $55.0/MWh causes wind to be the most economic option.

At lower cost wind energy assumptions of $42.5, $45.0 and $50.0/MWh, installing enough wind to meet 10% goal at the end of 2015 has lower NPV than the base case OPPD 15 Year Plan which has wind installed in 2016, 2018 and 2020 at $55.0/MWh. The above costs are all given in real dollars (2012$'s). The main reasoning behind this

scenario is current expectation that wind energy costs will not be as low as $50/MWh by the 2016 – 2020 timeframe but may be this low before 2015. Even when wind is priced as low as $42.5/MWh it is still less expensive in NPV terms to install 180 MW of it in 2016, 2018 and 2020 than it is to install it in 2013, 2014 and 2015 at this same low, real cost, that is, it is better to delay if such low wind prices could be achieved in 2016, 2018 and 2020.

Attachments

Attachment 1

Load and Generation Capability (Summer)

Summer Conditions (May 1 to October 31)

	2011*	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1. Seasonal System Demand																
Base Peak (June 2011 LF)	2498	2470	2541	2585	2611	2651	2705	2753	2800	2835	2891	2939	2988	3031	3094	3148
Less Demand Side Management	-30	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50
Less Curtailable Load	0	-67	-67	-67	-67	-67	-67	-67	-67	-67	-67	-67	-67	-67	-67	-67
Total	2468	2353	2424	2468	2494	2534	2588	2636	2683	2718	2774	2822	2871	2914	2977	3031
2. Annual System Demand	2468	2353	2424	2468	2494	2534	2588	2636	2683	2718	2774	2822	2871	2914	2977	3031
3. Firm Purchases - WAPA	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
4. Firm Sales																0
Wholesale Towns (a)	13	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15
NSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	13	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15
5. Seasonal Adj. Net Demand (1-3+4)	2399	2284	2355	2399	2425	2465	2519	2568	2615	2650	2705	2754	2804	2846	2909	2964
6. Adjusted Net Demand (2-3+4)	2399	2284	2355	2399	2425	2465	2519	2568	2615	2650	2705	2754	2804	2846	2909	2964
7. Net Generating Capability																
Fort Calhoun	479	479	479	479	479	479	**554**	554	554	554	554	554	554	554	554	554
Nebraska City #1	652	652	652	652	652	652	652	652	652	652	652	652	652	652	652	652
Nebraska City #2	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
North Omaha	638	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627
Sarpy County	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
Jones Street	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cass County	323	323	323	323	323	323	323	323	323	323	**483**	483	483	**643**	643	643
Elk City Landfill Gas	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total	3223	3211	3211	3211	3211	3211	3286	3286	3286	3286	3446	3446	3446	3606	3606	3606
8. Participation Purchases																
Tecumseh (leased)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Wind Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified Peaking Purchase	0	0	0	0	0	0	0	0	**21**	**61**	0	**19**	**75**	0	**36**	**98**
Total	7	7	7	7	7	7	7	7	28	67	7	25	82	7	42	104
9. Participation Sales																
Nebraska City #2 Participants	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342
WAPA	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0
City of Gardner Kansas	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	0
MJMEUC	0	0	35	35	35	35	35	0	0	0	0	0	0	0	0	0
Total	412	412	397	397	397	397	397	362	342	342	342	342	342	342	342	342
10. Accredited Capability (7+8-9)	2817	2806	2821	2821	2821	2821	2896	2931	2971	3011	3111	3129	3186	3271	3306	3368
11. Net Reserve Capacity Obligation (6 X 13.64%)	327	312	321	327	331	336	344	350	357	361	369	376	382	388	397	404
12. Total Firm Capacity Obligation (5+11)	2727	2595	2676	2726	2756	2801	2863	2918	2971	3011	3074	3129	3186	3234	3306	3368
13. Surplus or Deficit Capacity (10-12)	91	210	144	94	65	19	33	13	0	0	36	0	0	36	0	0
14. Reserve Margin (10/5)	17.4%	22.8%	19.8%	17.6%	16.3%	14.4%	14.9%	14.1%	13.6%	13.6%	15.0%	13.6%	13.6%	14.9%	13.6%	13.6%
15. Capacity Margin ((1-5/10)	14.8%	18.6%	16.5%	14.9%	14.0%	12.6%	13.0%	12.4%	12.0%	12.0%	13.0%	12.0%	12.0%	13.0%	12.0%	12.0%

Summer Capability Changes:

Ft. Calhoun
75 MW - 2016 (HP Rotor)

Cass County #3: CT
160 MW - 2021

Cass County #4: CT
160 MW - 2024

Wind Energy (Nameplate)
60 MW - Dec 2010
40.5 MW - Dec 2011
76 MW - 2012-13
20 MW - 2016
80 MW - 2018
80 MW - 2020

* Data is actual.

(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)

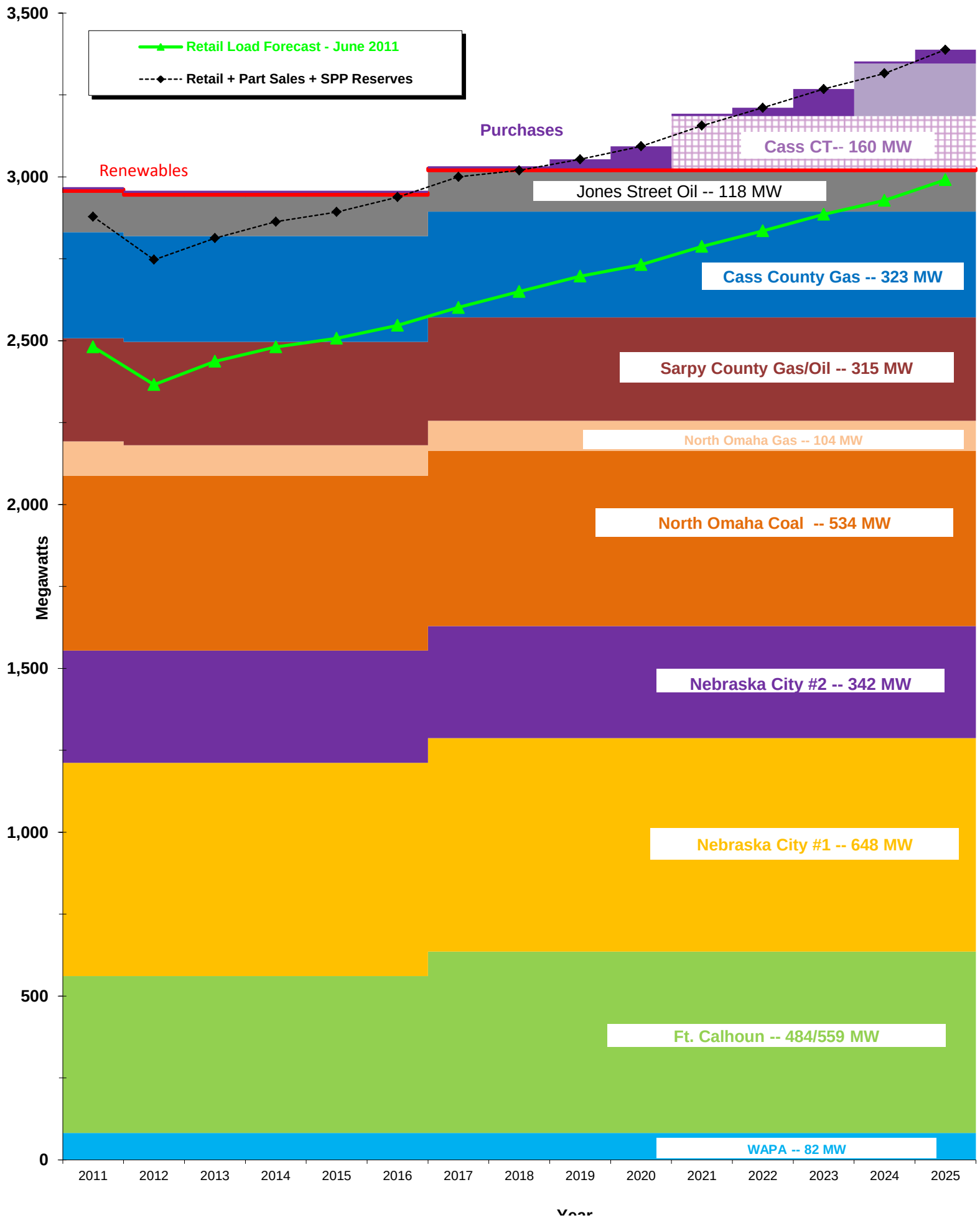
Winter Conditions (November 1 to April 30)

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
1. Seasonal System Demand															
Base Peak (June 2011 LF)	1771	1762	1814	1818	1868	1899	1933	1909	1996	2027	2063	2095	2072	2188	2207
Add New Customer Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1771	1762	1814	1818	1868	1899	1933	1909	1996	2027	2063	2095	2072	2188	2207
2. Annual System Demand	2353	2424	2468	2494	2534	2588	2636	2683	2718	2774	2822	2871	2914	2977	3031
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)	11	11	11	11	11	11	11	12	12	12	12	12	12	12	13
Total	11	11	11	11	11	11	11	12	12	12	12	12	12	12	13
5. Seasonal Adjusted Net Demand (1-3+4)	1740	1731	1783	1787	1837	1869	1903	1878	1965	1997	2032	2065	2042	2158	2177
6. Adjusted Net Demand (2-3+4)	2322	2393	2437	2463	2503	2557	2606	2653	2688	2743	2792	2842	2884	2947	3002
7. Net Generating Capability															
Fort Calhoun	479	479	479	479	479	554	554	554	554	554	554	554	554	554	554
Nebraska City #1	652	652	652	652	652	652	652	652	652	652	652	652	652	652	652
Nebraska City #2	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
North Omaha	534	534	534	534	534	534	534	534	534	534	534	534	534	534	534
Sarpy County	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
Jones Street	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cass County	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Elk City Landfill Gas	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total	2795	2795	2795	2795	2795	2870	2870	2870	2870	2870	2870	2870	2870	2870	2870
8. Participation Purchases															
Tecumseh (leased)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Wind Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
9. Participation Sales -															
Nebraska City #2 Participants	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342
WAPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
City of Gardner Kansas	20	20	20	20	20	20	0	0	0	0	0	0	0	0	0
MJMEUC	0	35	35	35	35	35	0	0	0	0	0	0	0	0	0
Total	362	362	362	362	362	362	342	342	342	342	342	342	342	342	342
10. Accredited Capability (7 + 8 - 9)	2440	2440	2440	2440	2440	2515	2535	2535	2535	2535	2535	2535	2535	2535	2535
11. Net Reserve Capacity Obligation (6 x 13.64%)	317	326	332	336	341	349	355	362	367	374	381	388	393	402	409
12. Total Firm Capacity Obligation (5 + 11)	2057	2057	2115	2123	2178	2218	2258	2240	2332	2371	2413	2453	2435	2560	2586
13. Surplus or Deficit Capacity (10 - 12)	383	383	325	317	261	297	277	294	202	164	121	82	99	-25	-51
14. Reserve Margin (10 / 5)	40.2%	41.0%	36.8%	36.5%	32.8%	34.6%	33.2%	34.9%	29.0%	26.9%	24.7%	22.8%	24.1%	17.5%	16.4%
15. Capacity Margin ((1-5/10)	28.7%	29.1%	26.9%	26.7%	24.7%	25.7%	24.9%	25.9%	22.5%	21.2%	19.8%	18.5%	19.4%	14.9%	14.1%

(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

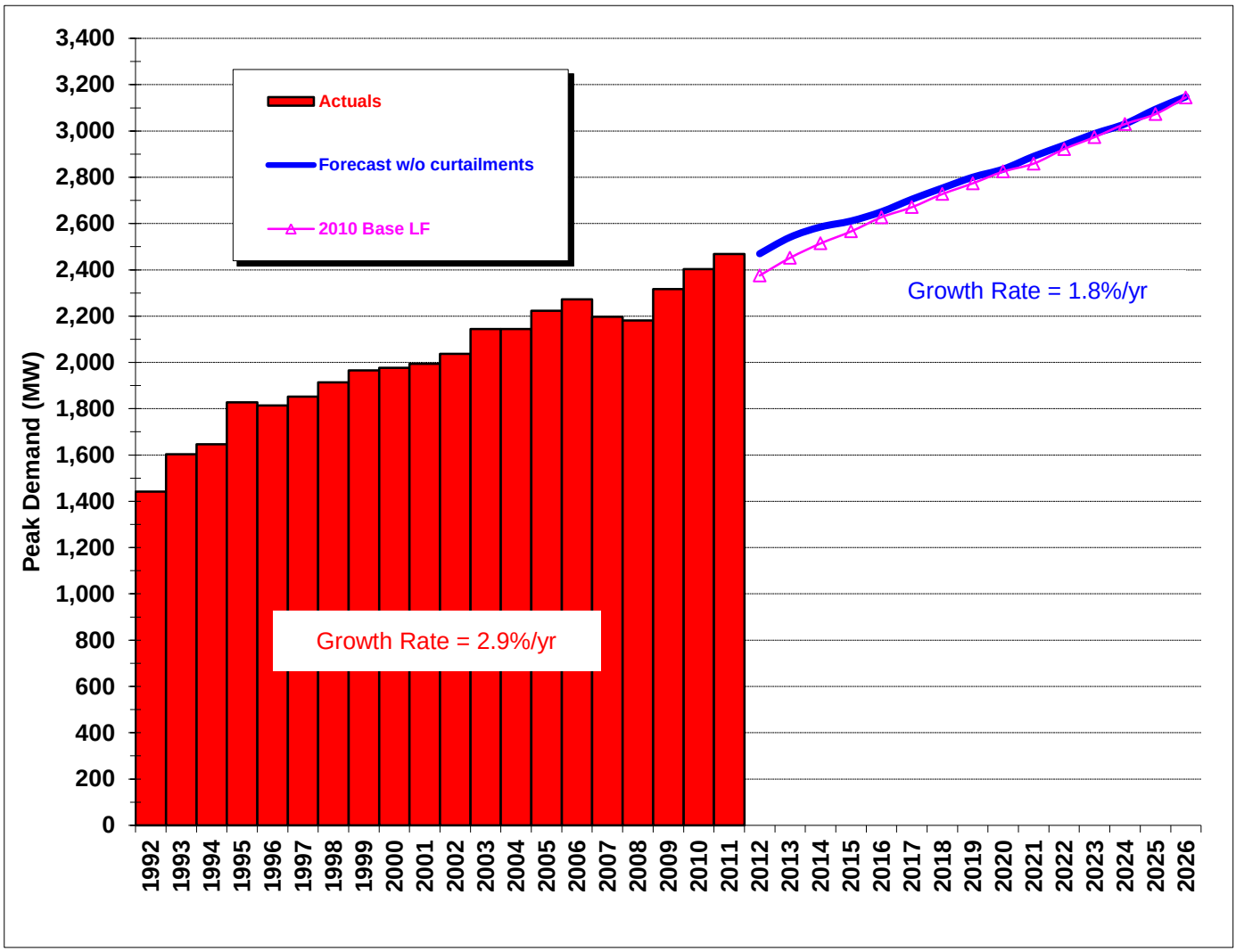
Load and Capability



Attachment 4

Annual System Peak Demand Forecast

June 2011 Forecast



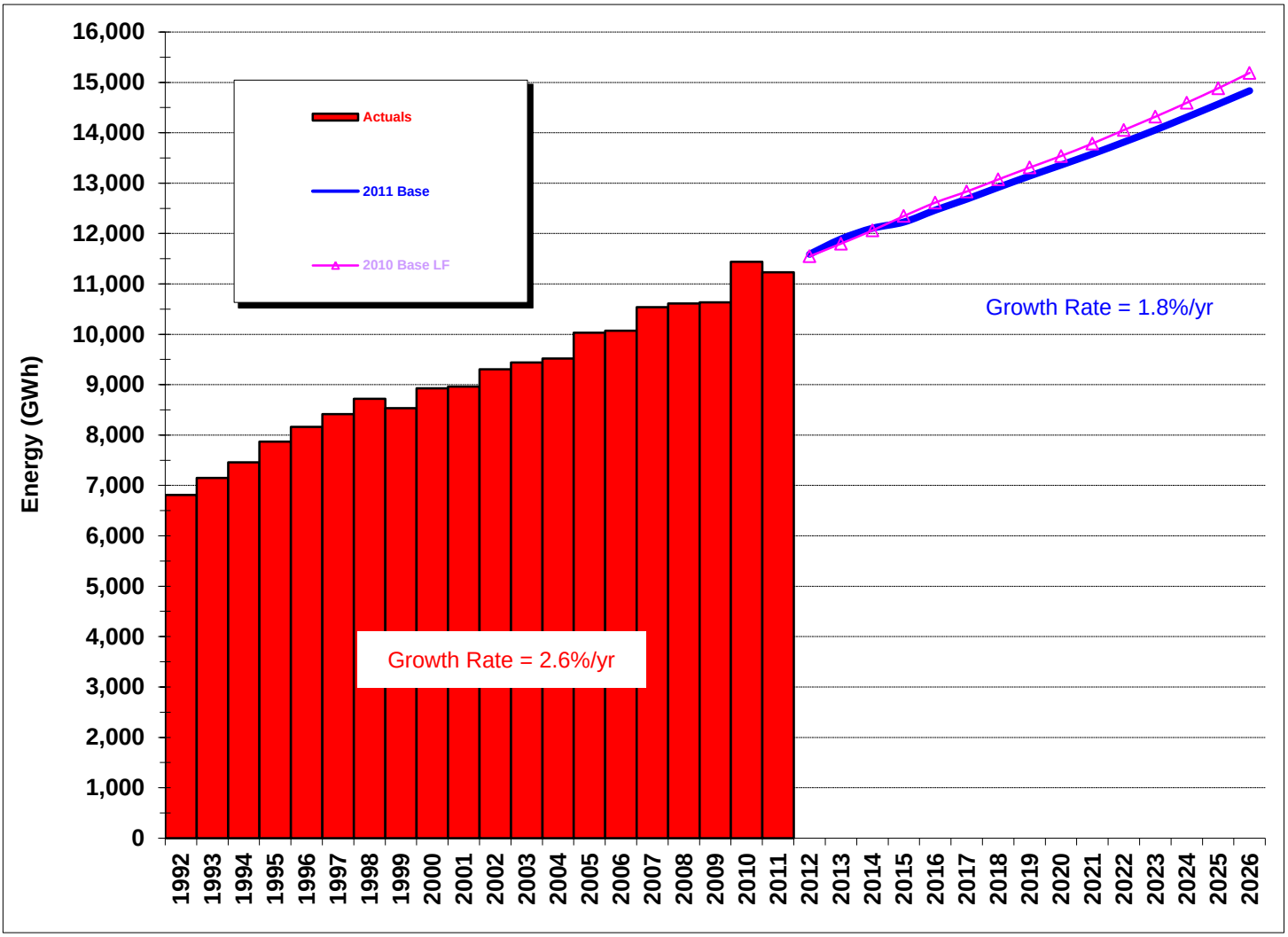
Year	Actual Peak MW	Date
1992	1,442.0	Jul-08
1993	1,603.1	Aug-17
1994	1,645.9	Aug-25
1995	1,828.0	Jul-12
1996	1,813.9	Jul-18
1997	1,851.8	Jul-25
1998	1,914.0	Jul-20
1999	1,965.6	Jul-28
2000	1,976.9	Aug-30
2001	1,994.1	Aug-01
2002	2,037.4	Jul-19
2003	2,144.8	Aug-25
2004	2,143.8	Jul-20
2005	2,223.3	Jul-22
2006	2,271.9	Jul-19
2007	2,197.4	Jul-18
2008	2,181.1	Jul-15
2009	2,316.4	Jun-23
2010	2,402.8	Aug-05
2011	2,468.3	Aug-01
Growth 92-11	2.9%	

	Forecast w/o curtailments			
Year	2011 Base	Growth	2010 Base LF	Change
2011	2,498	182	2,375	123
2012	2,470	-29	2,452	18
2013	2,541	71	2,514	27
2014	2,585	44	2,566	19
2015	2,611	26	2,627	-16
2016	2,651	40	2,671	-20
2017	2,705	54	2,727	-22
2018	2,753	48	2,774	-20
2019	2,800	47	2,825	-24
2020	2,835	35	2,859	-24
2021	2,891	55	2,922	-31
2022	2,939	48	2,973	-35
2023	2,988	50	3,030	-41
2024	3,031	42	3,073	-42
2025	3,094	63	3,145	-51
2026	3,148	54	3,204	-56
Nominal Growth Rate:	1.8%		1.9%	
Average Growth Rate:	43	MW/yr	55	

Attachment 5

Annual Net System Requirements Forecast

June 2011 Forecast



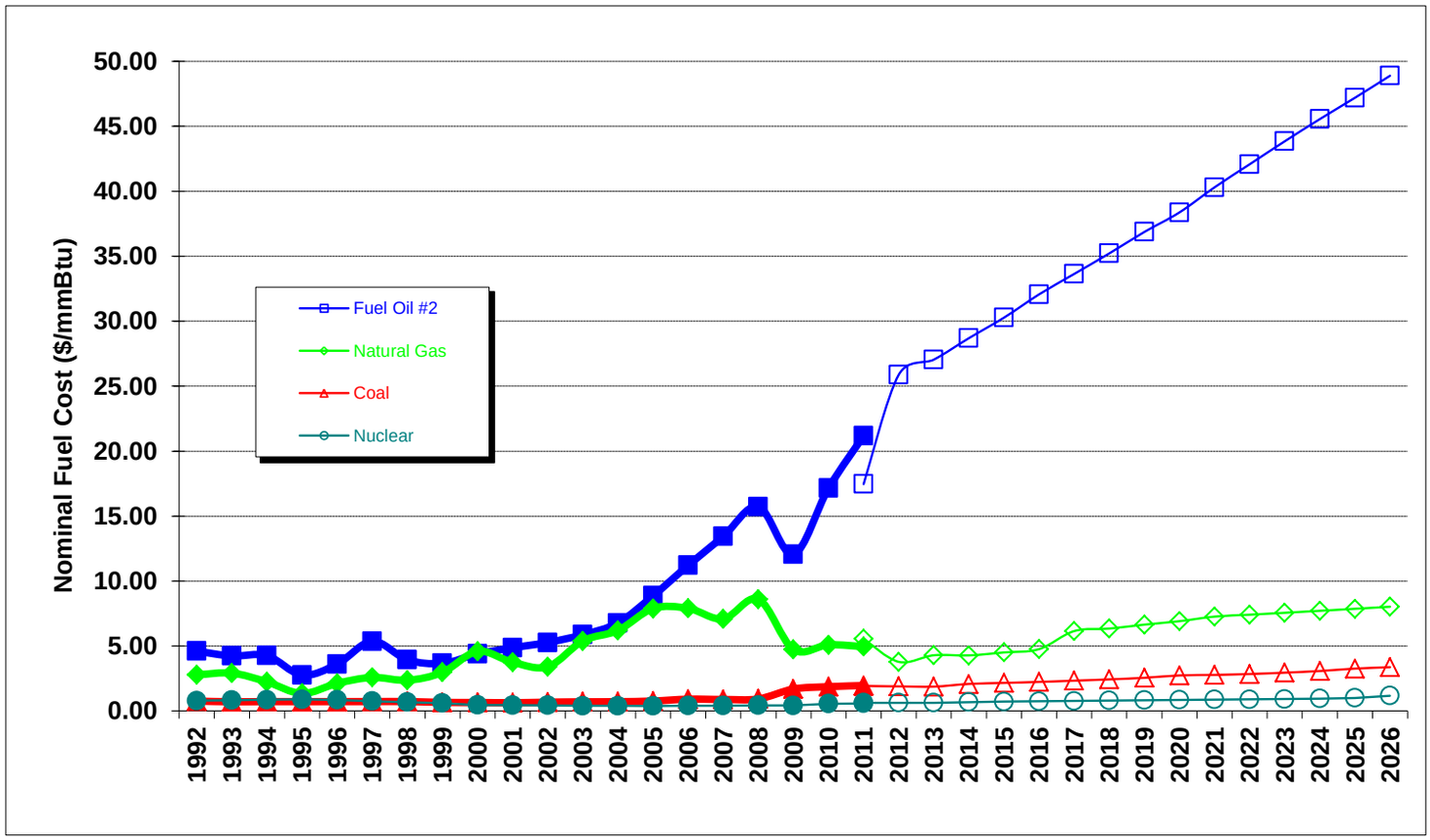
Year		Actual	Load Factor
1992		6,809	53.8%
1993		7,149	50.9%
1994		7,458	51.7%
1995		7,867	49.1%
1996		8,164	51.2%
1997		8,417	51.9%
1998		8,718	52.0%
1999		8,535	49.6%
2000		8,928	51.4%
2001		8,959	51.3%
2002		9,306	52.1%
2003		9,443	50.3%
2004		9,519	50.5%
2005		10,032	51.5%
2006		10,073	50.6%
2007		10,536	54.7%
2008		10,613	55.4%
2009		10,636	52.4%
2010		11,442	54.4%
2011	*	11,232	51.9%
Growth 92-11		2.7%	

	Forecast				
Year	2011 Base	LF	Growth	2010 Base LF	Change
2011	11,232	51.3%	-210	11,127	104
2012	11,589	53.4%	357	11,549	40
2013	11,891	53.4%	302	11,799	92
2014	12,105	53.5%	213	12,062	43
2015	12,228	53.5%	123	12,346	-119
2016	12,465	53.5%	237	12,614	-150
2017	12,683	53.5%	218	12,834	-151
2018	12,916	53.6%	233	13,073	-157
2019	13,142	53.6%	226	13,309	-167
2020	13,359	53.6%	217	13,539	-180
2021	13,581	53.6%	222	13,787	-206
2022	13,814	53.7%	233	14,054	-240
2023	14,056	53.7%	241	14,318	-263
2024	14,310	53.8%	255	14,595	-285
2025	14,569	53.8%	258	14,883	-314
2026	14,834	53.8%	265	15,189	-355
Growth Rate:	1.8%			2.0%	
Average Growth Rate:	240	GWh/yr		271	

Attachment 6

Fuel Forecast

Nominal $/MMBtu



		Actuals			
Year		Coal	Gas	Oil	Nuclear
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		0.93	8.61	15.73	0.43
2009		1.69	4.74	12.06	0.42
2010		1.87	5.10	17.15	0.57
2011	est	1.96	4.95	21.17	0.59

	Forecasts			
Year	Coal*	Gas**	Oil**	Nuclear^
2011	1.93	5.56	17.46	0.64
2012	1.89	3.78	25.88	0.63
2013	1.88	4.29	27.04	0.63
2014	2.08	4.28	28.70	0.68
2015	2.16	4.51	30.28	0.72
2016	2.24	4.76	32.07	0.74
2017	2.33	6.15	33.64	0.77
2018	2.43	6.35	35.22	0.80
2019	2.55	6.65	36.87	0.82
2020	2.74	6.92	38.37	0.85
2021	2.78	7.27	40.30	0.88
2022	2.85	7.41	42.08	0.89
2023	2.95	7.56	43.85	0.92
2024	3.08	7.71	45.56	0.95
2025	3.26	7.87	47.20	1.01
2026	3.37	8.03	48.89	1.17
Nominal Growth Rate:	3.79%	2.47%	7.10%	4.16%
Real Growth Rate:	1.36%	0.07%	4.6%	1.72%

* OPPD Bid Analysis

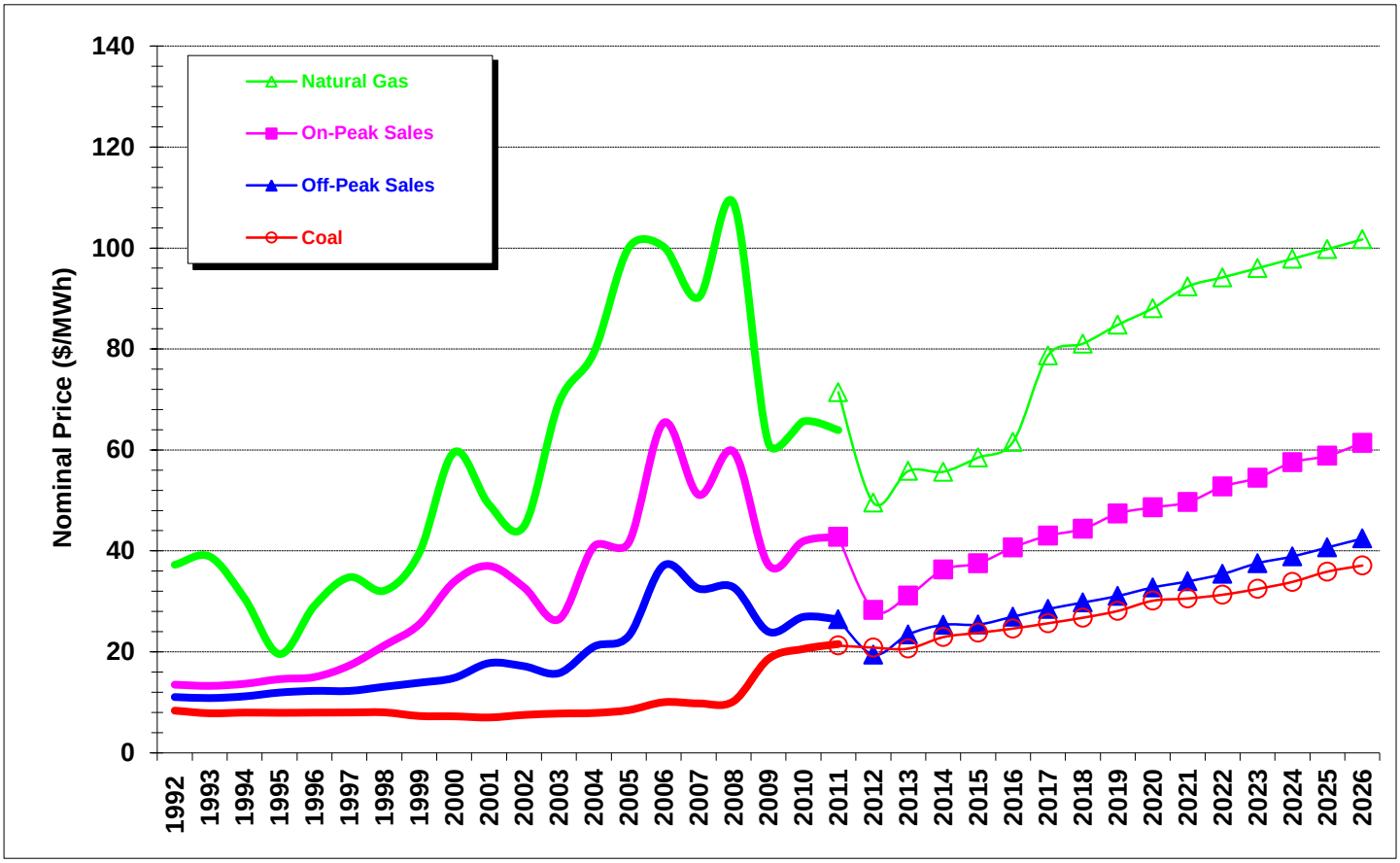
** Immediate years from OPPD agreements, out-year forecast from Ventyx

^ Uncontracted future uranium, conversion, enrichment and fabrication

Attachment 7A

Annual Wholesale Market Forecast

Nominal $/MWh



		Actuals			
Year		Gas	On-Peak	Off-Peak	Coal
1992		37.3	13.5	11.0	8.4
1993		38.9	13.3	10.8	7.8
1994		30.6	13.7	11.2	8.0
1995		19.6	14.6	11.9	7.9
1996		29.2	15.0	12.3	8.0
1997		34.8	17.3	12.3	8.0
1998		32.1	21.3	13.1	8.0
1999		39.6	25.5	13.9	7.3
2000		59.6	33.9	14.8	7.2
2001		49.2	37.0	17.8	7.0
2002		44.9	32.8	17.2	7.5
2003		69.4	26.5	15.8	7.8
2004		79.3	40.9	21.0	7.9
2005		100.1	41.7	23.2	8.5
2006		100.2	65.4	37.1	10.0
2007		90.2	51.1	32.5	9.8
2008		108.9	59.7	32.8	10.2
2009		61.3	37.2	24.0	18.6
2010		65.7	41.9	26.9	20.6
2011	est	63.9	42.8	26.4	21.5

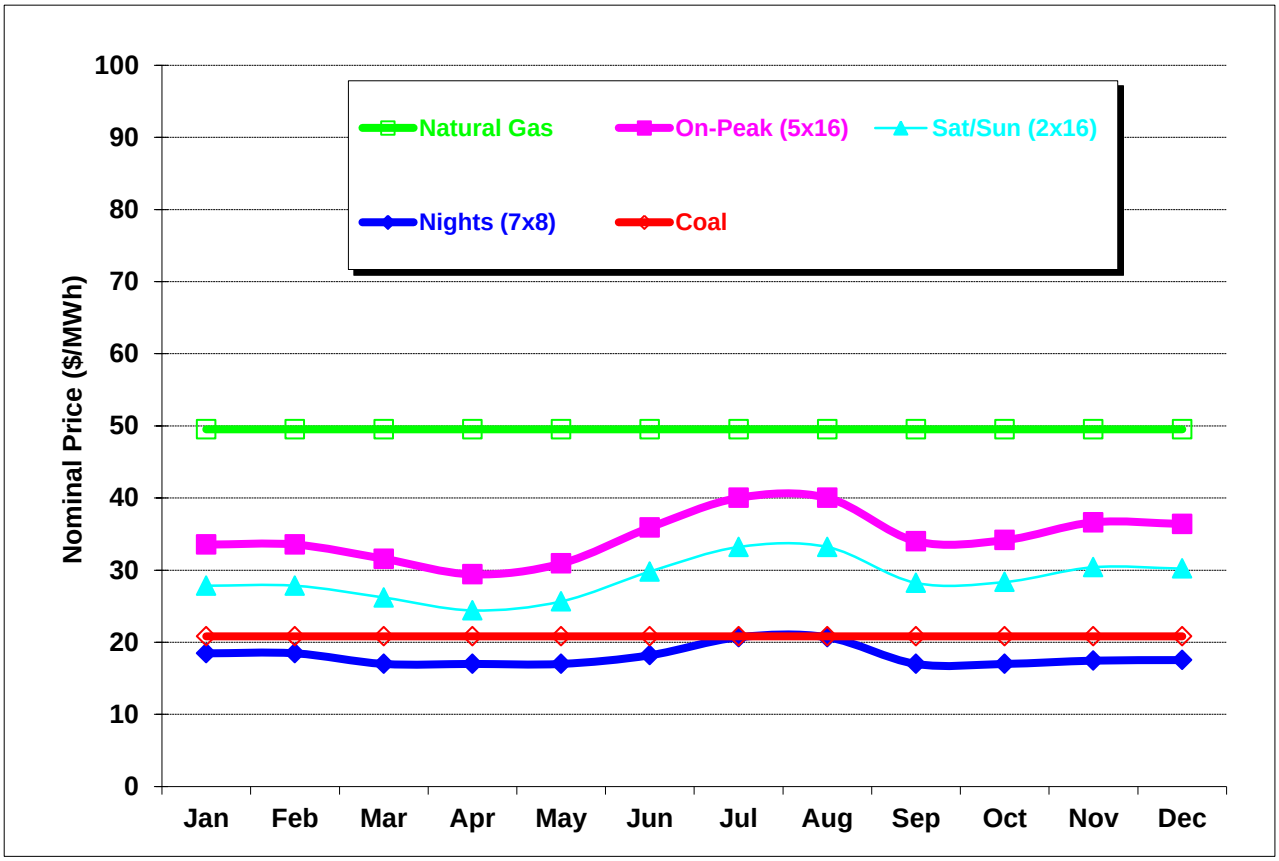
	Forecasts			
Year	Gas	On-Peak*	Off-Peak*	Coal
2011	71.4	42.8	26.4	21.2
2012	49.5	28.3	19.4	20.8
2013	55.8	31.1	23.4	20.6
2014	55.7	36.3	25.4	22.9
2015	58.5	37.5	25.4	23.8
2016	61.6	40.7	27.0	24.6
2017	78.7	43.0	28.5	25.7
2018	81.0	44.3	29.8	26.8
2019	84.8	47.4	31.1	28.1
2020	88.1	48.6	32.7	30.1
2021	92.4	49.6	33.9	30.6
2022	94.2	52.7	35.4	31.3
2023	96.0	54.5	37.6	32.5
2024	97.9	57.5	38.9	33.9
2025	99.8	58.8	40.7	35.9
2026	101.7	61.4	42.4	37.1
Nominal Growth Rate:	2.38%	2.44%	3.21%	3.79%
Real Growth Rate:	-0.02%	0.04%	0.79%	1.36%

* Source: Ventyx

Attachment 7B

Monthly Wholesale Market Forecast

Market Forecast for 2012 ($/MWh)

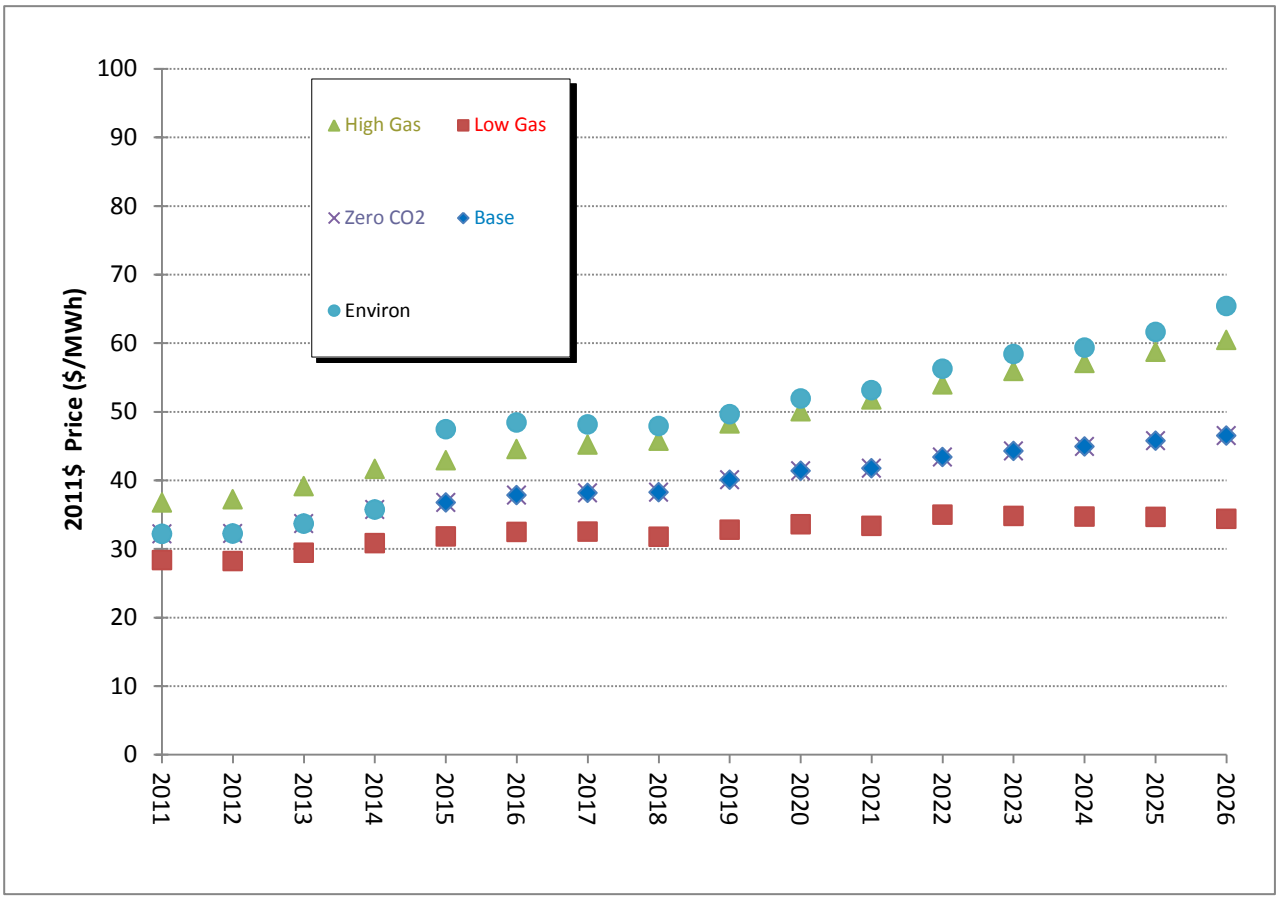


	Forecast				
Month	Gas	On-Peak	Sat/Sun	Nights	Coal
Jan	49.5	33.5	27.8	18.5	20.8
Feb	49.5	33.5	27.8	18.5	20.8
Mar	49.5	31.6	26.2	17.0	20.8
Apr	49.5	29.4	24.4	17.0	20.8
May	49.5	30.9	25.7	17.0	20.8
Jun	49.5	35.9	29.8	18.2	20.8
Jul	49.5	40.0	33.2	20.7	20.8
Aug	49.5	40.0	33.2	20.7	20.8
Sep	49.5	34.0	28.2	17.0	20.8
Oct	49.5	34.2	28.4	17.0	20.8
Nov	49.5	36.6	30.4	17.5	20.8
Dec	49.5	36.4	30.2	17.5	20.8
Average	49.5	38.8	29.9	21.3	20.8

Attachment 7C

Wholesale Market Forecast Scenarios

2011$ ($/MWh)

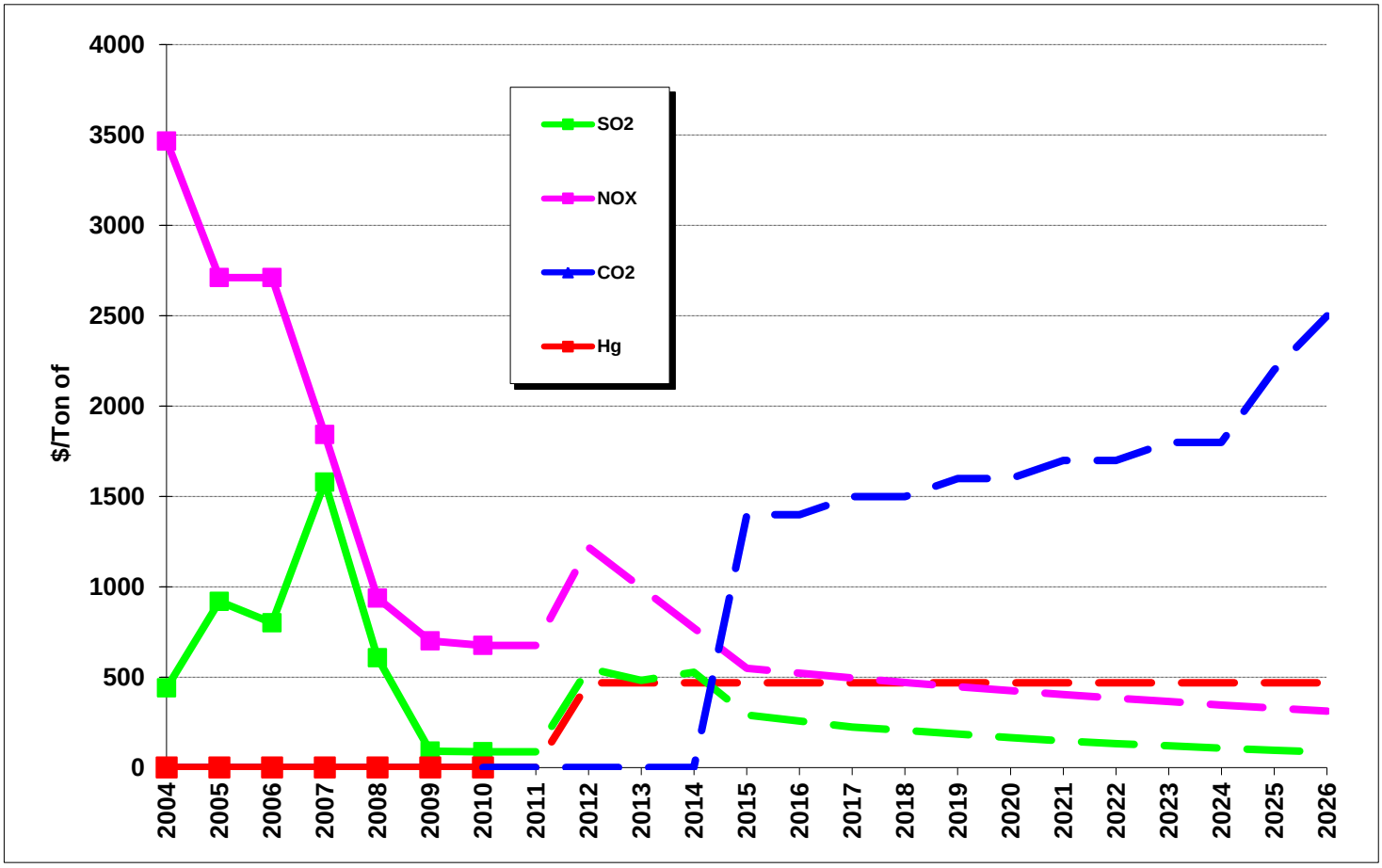


Year	Forecast				
	Base	Low Gas	High Gas	Zero CO2	Environ
2011	32.2	28.4	36.8	32.2	32.2
2012	32.2	28.2	37.2	32.2	32.2
2013	33.7	29.4	39.1	33.7	33.7
2014	35.7	30.8	41.6	35.7	35.7
2015	36.7	31.8	42.9	36.7	47.4
2016	37.8	32.5	44.5	37.8	48.4
2017	38.2	32.5	45.2	38.2	48.2
2018	38.2	31.8	45.8	38.2	47.9
2019	40.1	32.8	48.3	40.1	49.6
2020	41.4	33.6	50.1	41.4	51.9
2021	41.7	33.4	51.8	41.7	53.1
2022	43.4	35.0	54.0	43.4	56.3
2023	44.3	34.8	55.9	44.3	58.4
2024	44.9	34.7	57.1	44.9	59.4
2025	45.7	34.6	58.7	45.7	61.6
2026	46.5	34.4	60.5	46.5	65.4

Attachment 8

Environmental Externality/Allowance Trading Forecast

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



	Previous Forecasts (Nominal $)			
Year	SO_2	NO_X	CO_2	Mercury
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
2009	90	700	0	0
2010	87	675	0	0

	Future Forecasts (2012 $)			
Year	SO_2	NO_X	CO_2	Mercury
2011	87	675	0	469
2012	549	1219	0	469
2013	483	996	0	469
2014	527	773	0	469
2015	290	549	1400	469
2016	257	522	1400	469
2017	224	496	1500	469
2018	206	471	1500	469
2019	185	448	1600	469
2020	166	425	1600	469
2021	148	404	1700	469
2022	133	384	1700	469
2023	120	365	1800	469
2024	108	346	1800	469
2025	96	329	2200	469
2026	86	313	2500	469

(1) SO_2 Allowance Cost: Pre 2011 Acid Rain Program, Post 2012 Cross State Air Pollution Rule.

(2) NO_X Allowance Cost: 2004-11 based on NO_X SIP Market; Post 2012 Cross State Air Pollution Rule

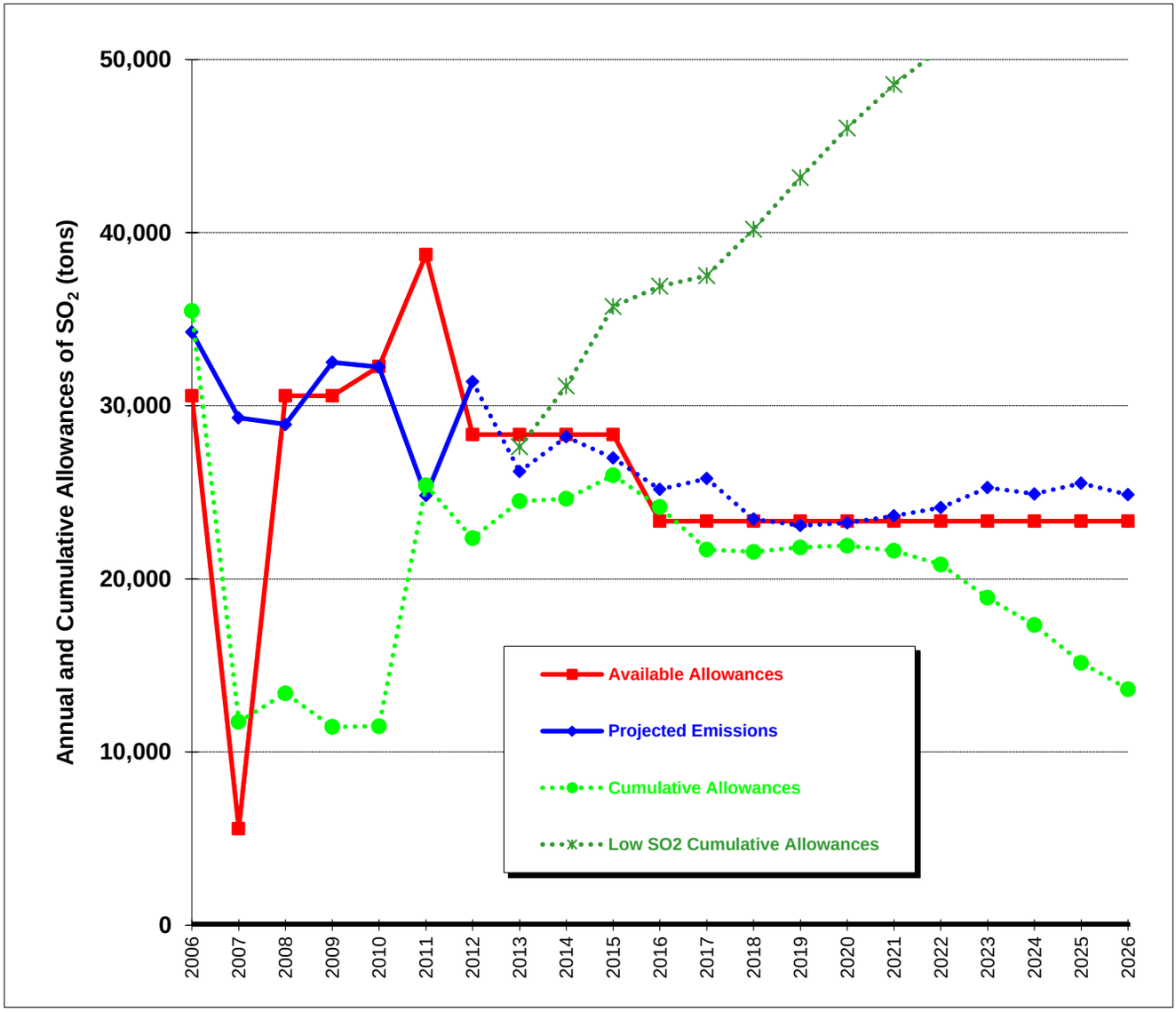
(3) CO_2 Allowance Cost is estimate of a legislated CO_2 Cap and Trade Program.

(4) Mercury Allowance Cost is estimated market price though a Mercury Cap and Trade is unlikely.

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) Bought 9,700 allowances in 2009 and 5,000 allowances per year 2010-2014.
(3) Projected emissions based on 2012 fuel budget data base (FB1226) and 2011 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, 2012 and beyond.

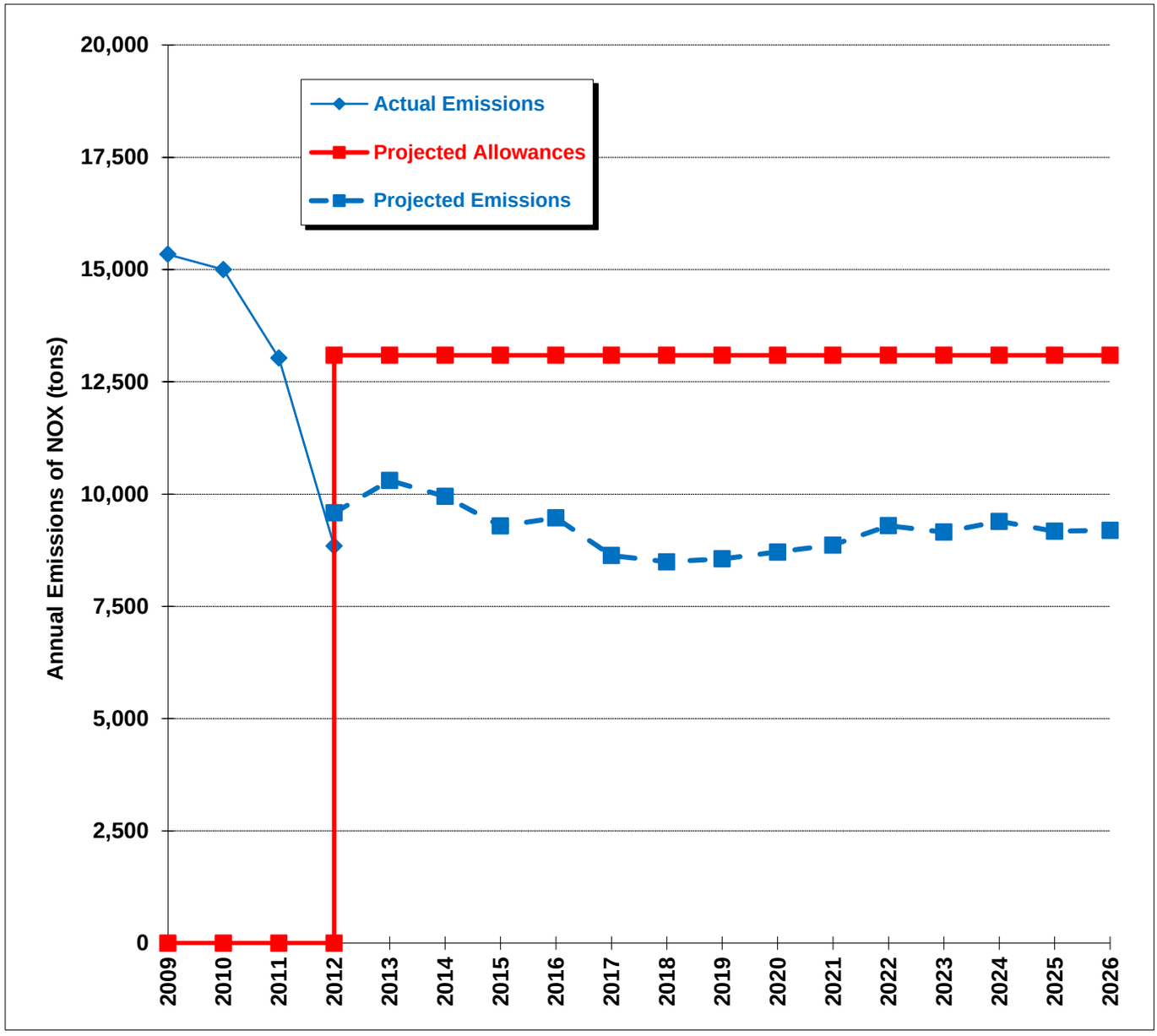
Tons of SO_2

Year		Projected Emissions	Available Allowances	Cumulative (Deficit)	Year	Projected Emissions	Available Allowances	Cumulative (Deficit)
2005	act	34,258	30,573	35,475	2016	25,799	23,334	21,686
2006	act	29,310	5,573	11,738	2017	23,457	23,334	21,563
2007	act	28,923	30,573	13,388	2018	23,081	23,334	21,816
2008	act	32,511	30,573	11,450	2019	23,231	23,334	21,919
2009	act	32,233	32,273	11,490	2020	23,634	23,334	21,619
2010	act	24,811	38,729	25,408	2021	24,117	23,334	20,835
2011	est	31,392	28,334	22,350	2022	25,264	23,334	18,906
2012		26,195	28,334	24,489	2023	24,904	23,334	17,335
2013		28,197	28,334	24,625	2024	25,517	23,334	15,152
2014		26,980	28,334	25,979	2025	24,859	23,334	13,627
2015		25,162	23,334	24,151	2026	24,877	23,334	12,083

Attachment 10

NO_X Emissions Under EPA Standard

(Tons NO_X)



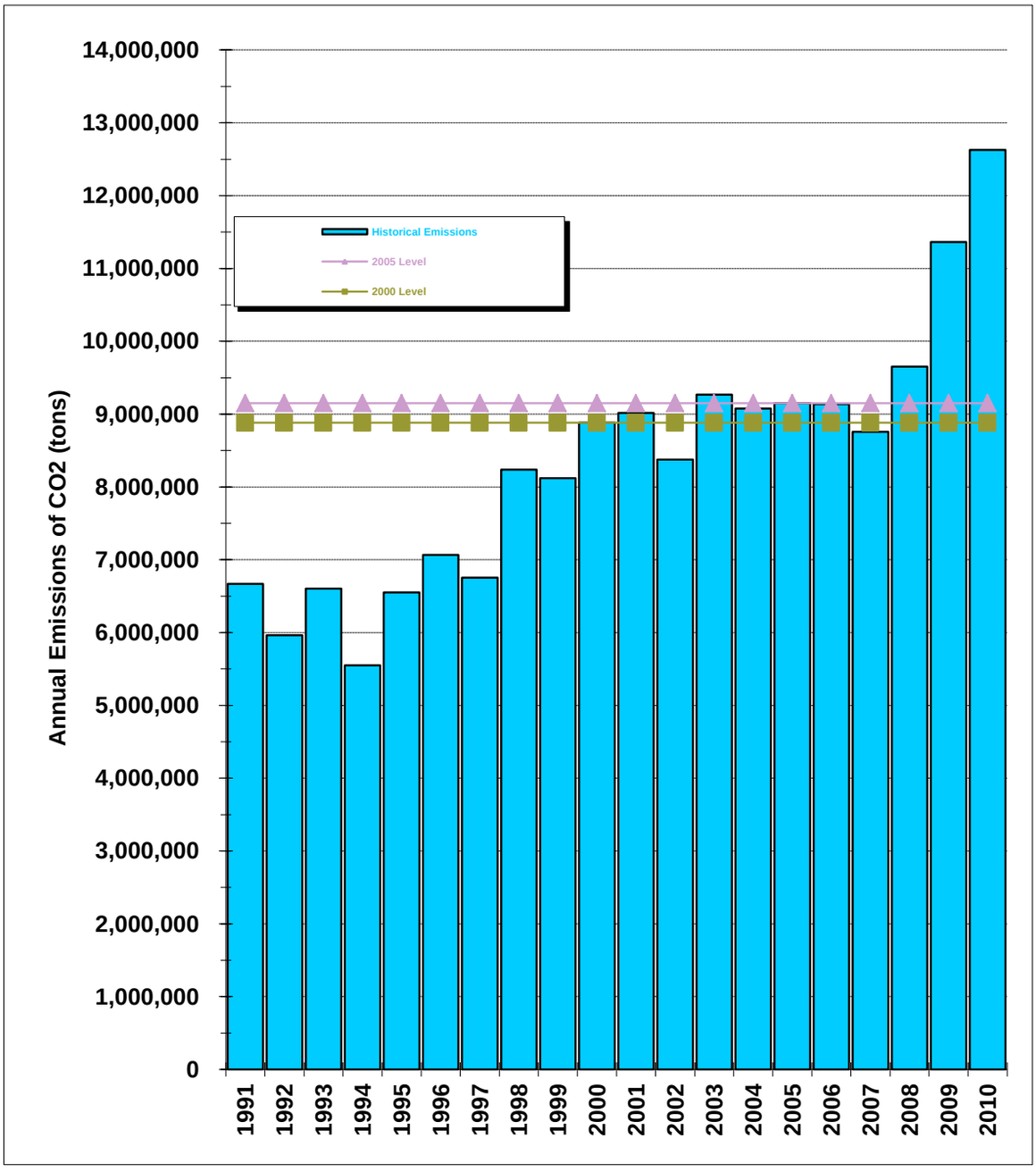
Notes: (1) Projected emissions based on 2011 IRP PROVIEW.
(2) Based on NO_X emission rates of 0.302 lb/MMBtu for North Omaha 1-3, 0.327 for NO#4, 0.32 for NO#5, 0.23 for Nebraska City #1 after 2010, and 0.07 for Nebraska City #2.
(3) Projected allowances based on Cross State Air Pollution Rule 2011 IRP analysis assumes 2012 implementation.
* Actual

Tons of NO_X

Year		Projected Emissions	Projected Allowances	Surplus (Deficit)	Year	Projected Emissions	Projected Allowances	Surplus (Deficit)
2009	*	15,339			2018	8,492	13,094	3,802
2010	*	15,000			2019	8,558	13,094	4,536
2011	*	13,031			2020	8,710	13,094	4,384
2012		9,584			2021	8,865	13,094	4,229
2013		10,305	13,094	2,789	2022	9,297	13,094	3,797
2014		9,950	13,094	3,144	2023	9,155	13,094	3,939
2015		9,292	13,094	3,802	2024	9,394	13,094	3,700
2016		9,471	13,094	3,623	2025	9,172	13,094	3,922
2017		8,632	13,094	4,462	2026	9,195	13,094	3,899

Attachment 11

Historical CO_2 Emissions



Year	Historical CO_2 Emissions (Tons)	
1991	6,670,499	
1992	5,964,798	
1993	6,605,230	
1994	5,549,839	
1995	6,549,452	
1996	7,065,915	
1997	6,755,530	
1998	8,238,134	
1999	8,120,249	
2000	8,880,412	2000 LEVEL

Year	Historical CO_2 Emissions (Tons)	
2001	9,015,858	
2002	8,376,715	
2003	9,266,668	
2004	9,078,732	
2005	9,150,393	2005 LEVEL
2006	9,135,762	
2007	8,754,603	
2008	9,651,847	
2009	11,362,252	
2010	12,628,262	

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

Attachment 12

Supply-Side Options

2012$

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%	1,733	1.7	3.1
LFGTE Greenfield	6	Methane	95%	2,203	1.6	3.3
Landfill Gas to Energy (LFGTE)	6	Methane	85%	2,203	1.6	3.6
Coal, Wood Retrofit ***	100	Wood	85%	3,108	1.8	4.6
Combined Cycle (CC)	300	Natural Gas	85%	1,403	6.6	7.9
800 MW Coal	800	Coal	85%	2,813	6.5	8.9
Coal Gasification CC (IGCC)	520	Coal	85%	3,914	6.0	9.5
300 MW Coal	300	Coal	85%	3,921	6.0	9.5
Advanced Nuclear (AP1200)	1000	Uranium	85%	6,058	4.2	9.5
Fluidized Bed	200	Coal	85%	3,357	6.6	9.6
150 MW Coal Greenfield	150	Coal	85%	4,036	6.4	10.0
800 MW Coal, CO2 Capture	800	Coal	85%	4,658	7.0	11.0
Whole Tree	100	Wood	85%	2,321	9.1	11.2
Combustion Turbine (HCF)	110	Natural Gas	85%	858	10.6	11.4
Fuel Cell	100	Natural Gas	85%	5,006	8.3	13.1
Municipal Solid Waste (MSW)	40	Refuse	85%	6,565	7.7	13.5
Switch Grass ***	100	Grass	85%	5,442	9.1	13.9
Bio-diesel (internal comb.)	5	Plant oil	85%	881	38.9	39.7
Intermediate						
Wind w/o backup (w/o REPI)	50	Wind	36%	2,148	1.3	7.0
Combined Cycle (CC)	300	Natural Gas	36%	1,403	7.1	10.0
Wind w/backup (w/o REPI)	50	Wind	36%	2,920	7.8	14.9
Wind w/o backup (w/o REPI)	50	Wind	24%	2,148	1.5	10.1
Combined Cycle (CC)	300	Natural Gas	24%	1,403	7.5	11.9
Wind w/backup (w/o REPI)	50	Wind	24%	2,920	8.0	18.6
Solar Photovoltaic (Fixed Plate)	50	Sunlight	24%	5,362	1.1	19.0
Solar Thermal (Parabolic)	80	Sunlight	24%	5,190	5.5	22.9
Peaking						
5 Hour Battery	100	Coal	5%	1,073	8.2	25.5
Combustion Turbine (CT)	160	Natural Gas	5%	858	14.2	26.9
Compressed Air Storage (CAES)	100	Coal	5%	1,242	10.3	30.3
Pumped Storage	100	Coal	5%	1,242	9.9	33.1
Combined Cycle (CC)	300	Natural Gas	5%	1,403	12.3	33.1
Aero-Derivative (LM 6000)	50	Natural Gas	5%	1,412	13.7	34.7
Diesel	5	Diesel	5%	881	53.6	66.6

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

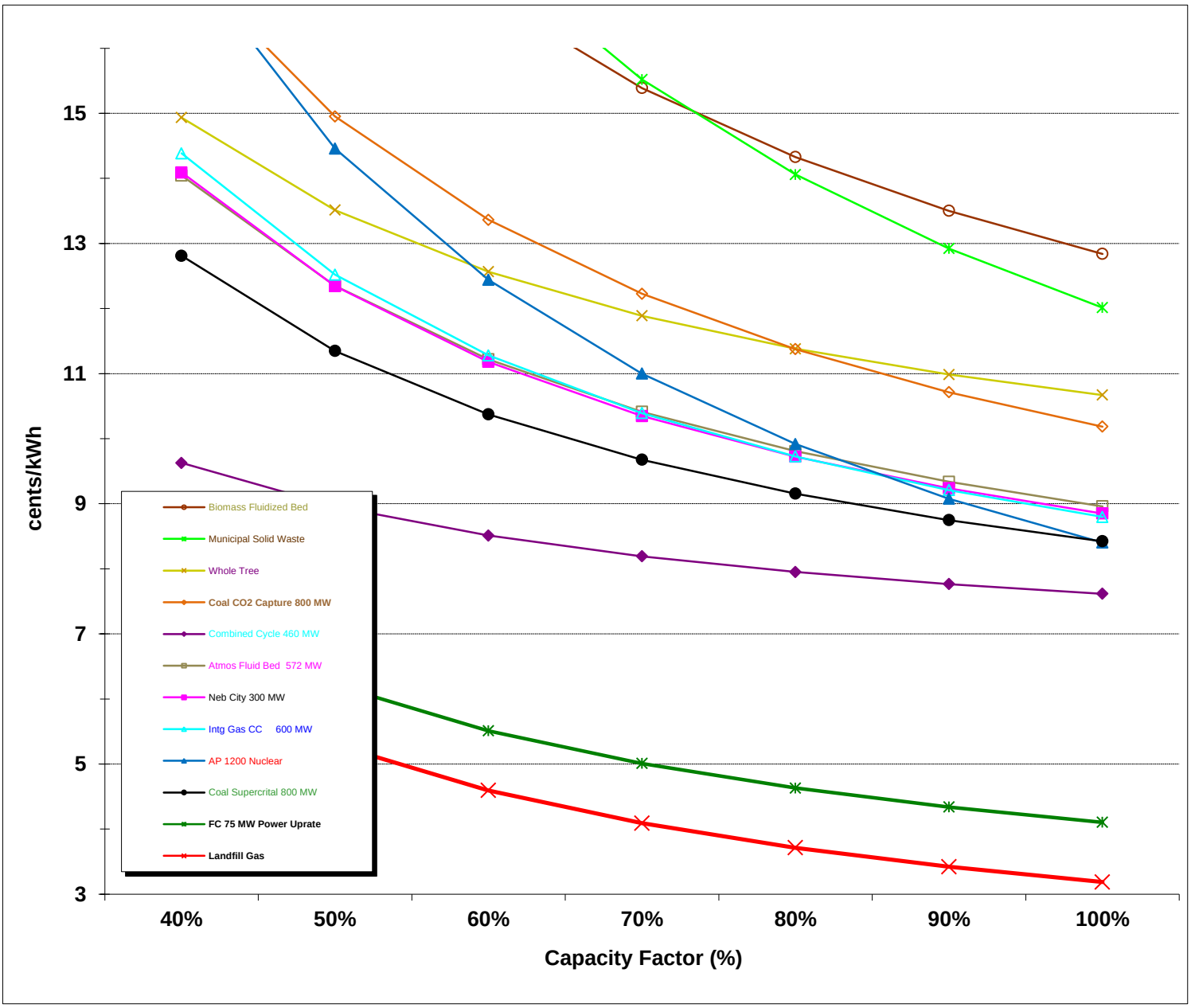
** Operating Cost includes fuel, O&M, and environmental (SO2, NOX, CO2, Particulates) Costs.

*** Biomass (wood, grass, crops) fuel costs will vary based on availabilty and proximity.

Attachment 13A

Baseload Screening Curve Analysis

Levelized 2012$

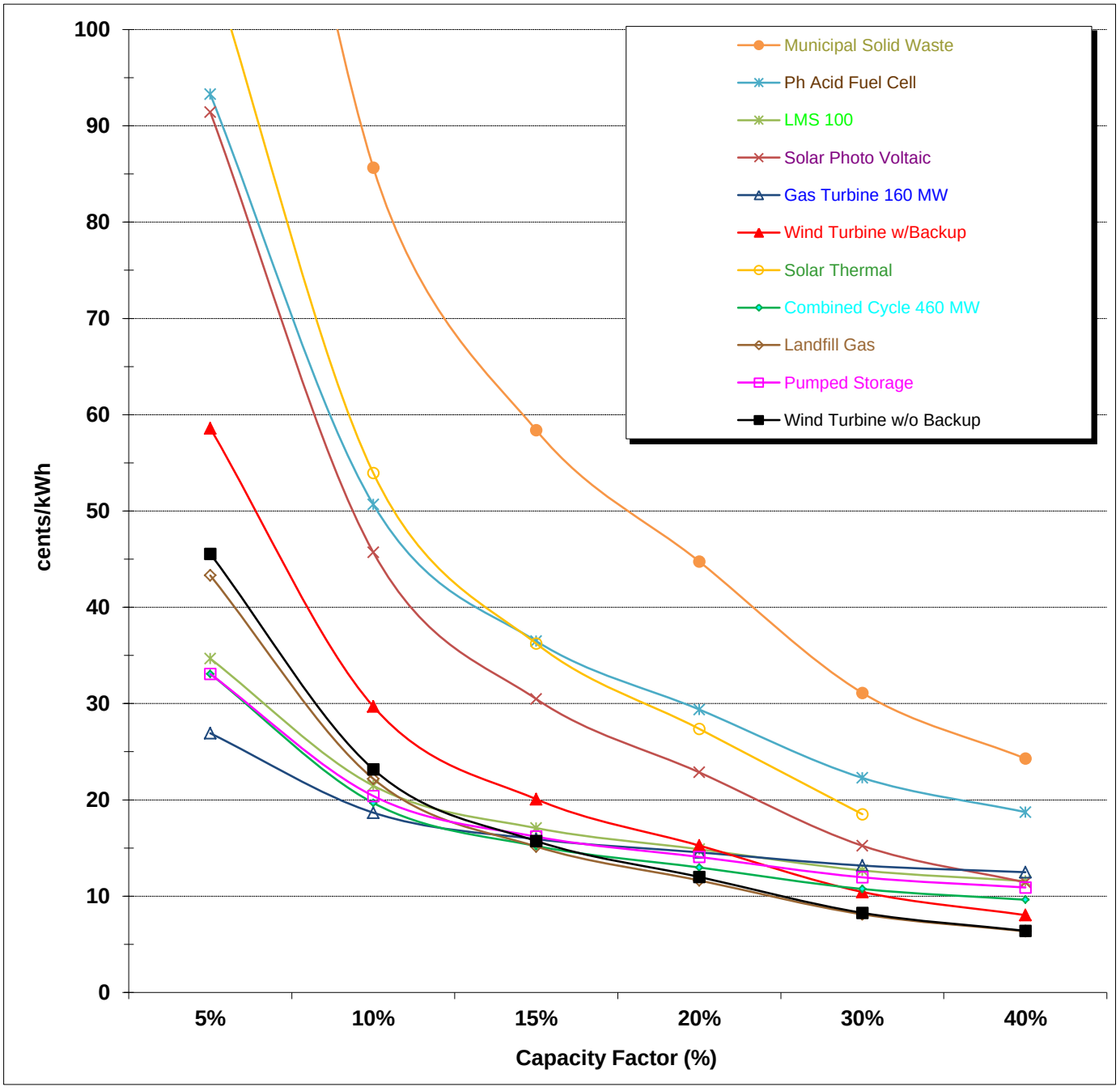


	Capacity Factor						
LEVELIZED COST (cents/kWh)	40%	50%	60%	70%	80%	90%	100%
Biomass Fluidized Bed	21.8	18.8	16.8	15.4	14.3	13.5	12.8
Municipal Solid Waste	24.3	20.2	17.5	15.5	14.1	12.9	12.0
Whole Tree	14.9	13.5	12.6	11.9	11.4	11.0	10.7
Coal CO2 Capture 800 MW	17.3	15.0	13.4	12.2	11.4	10.7	10.2
Combined Cycle 460 MW	9.6	9.0	8.5	8.2	8.0	7.8	7.6
Atmos Fluid Bed 572 MW	14.0	12.3	11.2	10.4	9.8	9.3	9.0
Neb City 300 MW	14.1	12.3	11.2	10.3	9.7	9.2	8.8
Intg Gas CC 600 MW	14.4	12.5	11.3	10.4	9.7	9.2	8.8
AP 1200 Nuclear	17.5	14.5	12.4	11.0	9.9	9.1	8.4
Coal Supercrital 800 MW	12.8	11.3	10.4	9.7	9.2	8.7	8.4
FC 75 MW Power Uprate	7.3	6.2	5.5	5.0	4.6	4.3	4.1
Landfill Gas	6.4	5.3	4.6	4.1	3.7	3.4	3.2

Attachment 13B

Peaking/Intermediate Screening Curve Analysis

Levelized 2012$

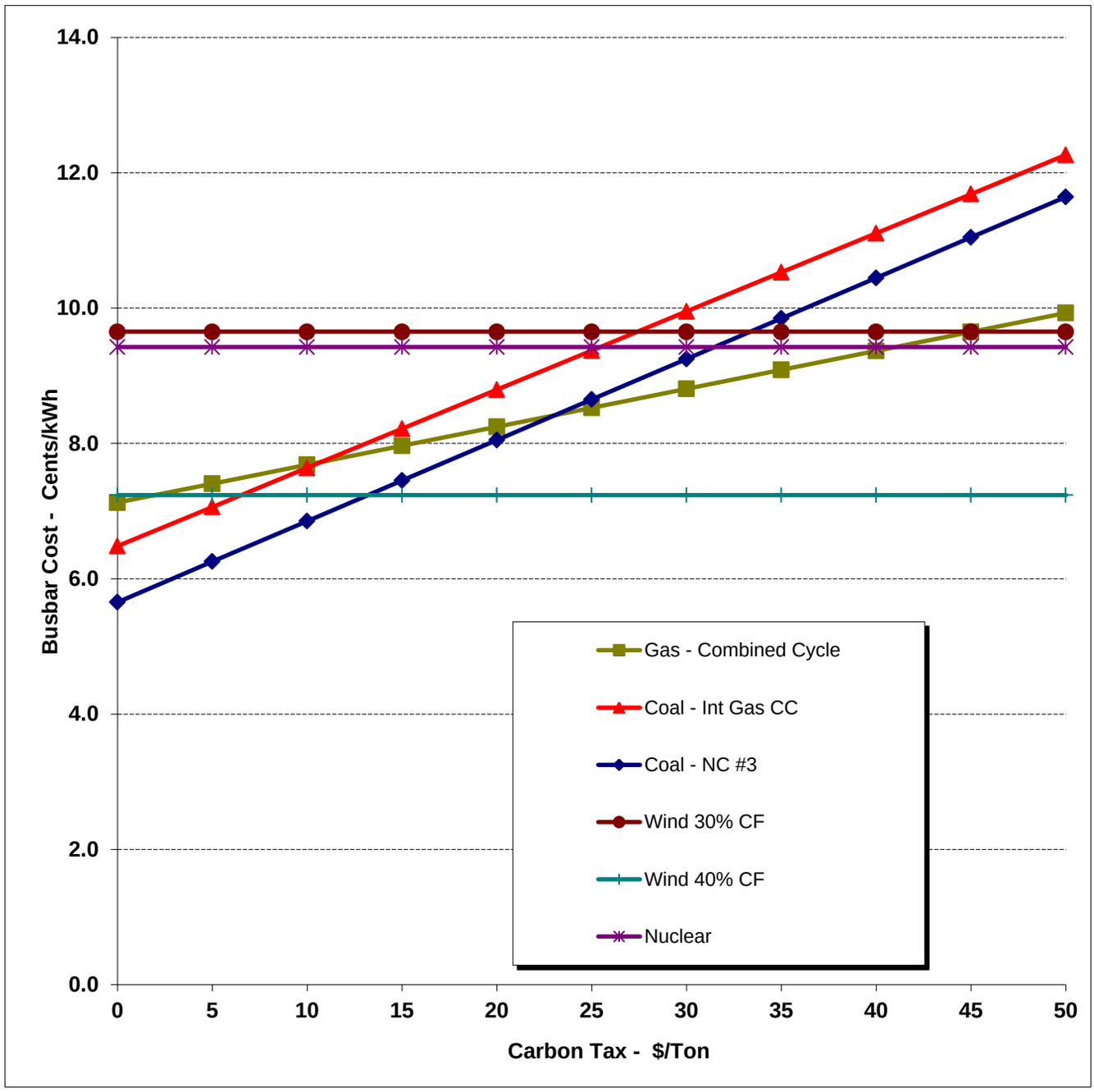


	Capacity Factor					
LEVELIZED COST (cents/kWh)	5%	10%	15%	20%	30%	40%
Municipal Solid Waste	167.5	85.7	58.4	44.7	31.1	24.3
Ph Acid Fuel Cell	93.3	50.7	36.5	29.4	22.3	18.7
LMS 100	34.7	21.5	17.1	14.9	12.7	11.6
Solar Photo Voltaic	91.4	45.7	30.5	22.9	15.2	11.4
Gas Turbine 160 MW	26.9	18.7	15.9	14.6	13.2	12.5
Wind Turbine w/Backup	58.6	29.7	20.1	15.3	10.4	8.0
Solar Thermal	107.1	53.9	36.2	27.4	18.5	14.1
Combined Cycle 460 MW	33.1	19.7	15.2	13.0	10.7	9.6
Landfill Gas	43.3	22.2	15.2	11.6	8.1	6.4
Pumped Storage	33.1	20.4	16.2	14.1	12.0	10.9
Wind Turbine w/o Backup	45.5	23.2	15.7	12.0	8.3	6.4

Attachment 13C

Busbar Cost - Function of Carbon Tax

Levelized 2012$



	Carbon Tax $/Ton					
LEVELIZED COST (cents/kWh)	0	10	20	30	40	50
Gas - Combined Cycle	6.9	7.5	8.0	8.6	9.2	9.7
Coal - Int Gas CC	7.4	8.6	9.8	11.0	12.2	13.5
Coal - Pulverized	6.7	8.1	9.4	10.8	12.1	13.5
Wind 30% CF	8.3	8.3	8.3	8.3	8.3	8.3
Wind 40% CF	6.4	6.4	6.4	6.4	6.4	6.4
Nuclear	9.1	9.1	9.1	9.1	9.1	9.1

Attachment 14

Ft. Calhoun

Expected Power Uprate Capacity Gains (MW)

Prior Uprate Ratings	Practical Monthly Cont Maximum	2011 SPP Capability	2012 SPP Capability
Jan	509.0	484.0	478.6
Feb	509.0	484.0	478.6
Mar	508.0	484.0	478.6
Apr	505.0	484.0	478.6
May	500.0	484.0	478.6
Jun	492.0	478.6	478.6
July	484.0	478.6	478.6
Aug	487.0	478.6	478.6
Sep	495.0	478.6	478.6
Oct	503.0	478.6	478.6
Nov	508.0	478.6	478.6
Dec	509.0	478.6	478.6
Avg	500.8	480.9	478.6

Power Uprate, HP Turbine	Increase by Month
Jan	79
Feb	79
Mar	79
Apr	79
May	79
Jun	79
July	75
Aug	75
Sep	79
Oct	79
Nov	79
Dec	79

With Uprate	Practical Monthly Cont Maximum	SPP Capability
Jan	588	554
Feb	588	554
Mar	587	554
Apr	584	554
May	579	554
Jun	571	554
July	559	554
Aug	562	554
Sep	574	554
Oct	582	554
Nov	587	554
Dec	588	554

Derate %	Prior Uprate, Practical Monthly Derate	Power Uprate Practical Monthly Derate
Jan	0.00%	0.00%
Feb	0.00%	0.00%
Mar	0.20%	0.17%
Apr	0.79%	0.68%
May	1.77%	1.53%
Jun	3.34%	2.89%
July	4.91%	4.93%
Aug	4.32%	4.42%
Sep	2.75%	2.38%
Oct	1.18%	1.02%
Nov	0.20%	0.17%
Dec	0.00%	0.00%

Ft Calhoun Site Limit is Raised to 607 MW (from 540) - approved by MAPP DRS - SPP Approval Expected

SPP Summer Season is June - September, Currently OPPD is not establishing a Higher Winter Rating

Attachment 15

Suboptimal Cases

"#" Column: if row is flagged, delta is from $0 CO2 BnchMrk

	Next Intermediate or Baseload		Case Name	NPV	#	Delta	%
Benchmark Case							
Base Case	2027 CC	2032 Nuc	B01	**19199**		Base	Base
$0/Ton CO2 Benchmark	2032 NC.J	2033 CC	B06-C01N	**15233**		-3966	-20.7%
Alternatives to Timing of Cass County Station Conversion							
Cass Conversion to CC, Force in 2019	2019 CC C	2025 CC	B01-G19	**19696**		497	2.6%
Cass Conversion to CC, Force in 2020	2020 CC C	2025 CC	B01-G20	**19684**		485	2.5%
Cass Conversion to CC, Force in 2021	2021 CC C	2025 CC	B01-G21	**19673**		474	2.5%
Cass Conversion to CC, Force in 2022	2021 CC	2022 CC C	B01-G22	**19787**		588	3.1%
Cass Conversion to CC, Force in 2023	2021 CC	2023 CC C	B01-G23	**19768**		569	3.0%
Cass Conversion to CC, Force in 2024	2021 CC	2024 CC C	B01-G24	**19750**		551	2.9%
All New Comb Cycle Force in 2019	2019 CC	2030 Nuc	B01-G19A	**19319**		120	0.6%
All New Comb Cycle Force in 2020	2020 CC	2030 Nuc	B01-G20A	**19289**		90	0.5%
All New Comb Cycle Force in 2021	2021 CC	2030 Nuc	B01-G21A	**19260**		61	0.3%
All New Comb Cycle Force in 2022	2022 CC	2030 Nuc	B01-G22A	**19280**		81	0.4%
All New Comb Cycle Force in 2023	2023 CC	2030 Nuc	B01-G23A	**19252**		53	0.3%
All New Comb Cycle Force in 2024	2024 CC	2030 Nuc	B01-G24A	**19226**		27	0.1%
Alternative Technologies for Baseload							
No Coal or Gas (Adv. Nuclear Only)	2033 Nuc	2035 Nuc	B01-L	**13939**		-5260	-27.4%
Integrated Gas Comb Cycle - 300 MW	2021 IGCC	2030 CC	B01-N	**21318**		2119	11.0%
Ft Calhoun Power Uprate, Resource Planning Council Inputs							
Delayed 2019, $0/Ton CO2	2030 FC.J	2033 CC	B04-N-19	**15333**		100	0.7%
Delayed 2019, Base CO2	2027 CC	2032 Nuc	B04-M-19	**19379**		180	0.9%
No Power Uprate, $0/Ton CO2	2031 FC.J	2033 CC	B04-N-NO	**15380**		147	1.0%
No Power Uprate, Base CO2	2026 CC	2031 Nuc	B04-M-NO	**19492**		293	1.5%
2017 Power Uprate, $0/Ton CO2	2032 NC.J	2033 CC	B04-N-17	**15233**		0	0.0%
2017 Power Uprate, $0/Ton CO2, High	2032 NC.J	2033 CC	B04-N-13H	**15245**		12	0.1%
2017 Power Uprate, Base CO2, High	2027 CC	2032 Nuc	B04-M-17H	**19211**		12	0.1%
Environmental Regulation Economics - delta based on this section's benchmarks							
N Oma Benchmark w/FOM	2027 CC	2032 Nuc	B07-F	**19359**			
N Oma Benchmark w/FOM, $0/Ton CO2	2032 NC.J	2033 CC	B07-FN	**15393**			
N Oma 1,2,3 Retire 2017	2023 CC	2032 Nuc	B07-17	**19349**		-10	-0.1%
N Oma 1,2,3 Retire 2017, $0/Ton CO2	2029 FC.J	2033 CC	B07-17N	**15586**		193	1.3%
Demand-Side Management							
Remove 50 MW DSM from Base Case	2026 CC	2026 CC	B02-DSM	**19382**		183	1.0%
Base Case, 50 MW DSM in 2012	2027 CC	2032 Nuc	B01	**19199**		0	0.0%
50 MW DSM by 2014 with added efficiency	2026 CC	2032 Nuc	B02-DSM1	**18741**		-458	-2.4%
75 MW DSM by 2014 with added efficiency	2025 CC	2031 Nuc	B02-DSM3	**18737**		-462	-2.4%
100 MW DSM by 2014 with added efficiency	2024 CC C	2029 Nuc	B02-DSM2	**18596**		-603	-3.1%
AC Cycle, Industry Estimate	2025 CC	2031 Nuc	B00-A	**19153**		-46	-0.2%
AC Setback, Industry Estimate	2025 CC	2031 Nuc	B00-B	**19149**		-50	-0.3%
AC Clean, Industry Estimate	2027 CC	2033 Nuc	B00-C	**19335**		136	0.7%
Storage Technologies							
CAES, 100 MW, 2016	2026 CC	2032 Nuc	B01-A	**19006**		-193	-1.0%
Pumped Storage, 100 MW, 2020, '27, '28	2026 CC	2032 Nuc	B01-P	**19058**		-141	-0.7%
Advanced Battery, 100 MW, 2015	2026 CC	2032 Nuc	B01-C	**19169**		-30	-0.2%

Attachment 16

Sensitivity Cases

"#" Column: if row is flagged, delta is from $0 CO2 BnchMrk

		Next Intermediate or Baseload		Case Name	NPV	#	Delta	%
Benchmark Case								
Base Case		2027 CC	2030 Nuc	B01	**19199**		Base	Base
$0/Ton CO2 Benchmark		2032 NC.J	2033 CC	B06-C01N	**15233**		-3966	-20.7%
Load Forecast (1.8%/yr)								
Low	1.0%/yr	2030 Nuc	2033 Nuc	B02-S08L	**14213**		-4986	-26.0%
High	2.5%/yr	2025 CC C	2030 Nuc	B02-S08H	**23113**		3914	20.4%
Wholesale Prices Market ($31.6/MWh)								
60%	$19.0/MWH	2030 CC	2033 Nuc	B02-S12L	**18215**		-984	-5.1%
80%	$25.3/MWH	2028 CC	2033 Nuc	B02-S09L	**18958**		-241	-1.3%
120%	$37.9/MWH	2024 CC C	2029 Nuc	B02-S9H	**19016**		-183	-1.0%
No Interchange Sales		2027 CC	2033 Nuc	B02-E3	**19451**		252	1.3%
No Interchange Purchases		2024 CC C	2030 Nuc	B02-E1	**19522**		323	1.7%
No Interchange Sales and Purchases		2027 CC	2032 Nuc	B02-E2	**19802**		603	3.1%
Coal Costs (Base Case: $1.80/mmBtu Avg for NC & NO, see Attachment 6)								
Low	-25 cents/mmBtu	2027 CC	2032 Nuc	B02-S01L	**18669**		-530	-2.8%
High	+30 cents/mmBtu	2027 CC	2032 Nuc	B02-I1	**19821**		622	3.2%
Higher	+100 cents/mmBtu	2027 CC	2032 Nuc	B02-S01H	**21192**		1993	10.4%
Very High	+180 cents/mmBtu	2027 CC	2032 Nuc	B02-I2	**22676**		3477	18.1%
Debt Service and Study Variations								
Debt Service Coverage - 1.7		2030 CC	2033 CC	B02-J1	**22003**		2804	14.6%
Debt Service Coverage - 1.4		2027 CC	2032 Nuc	B02-J2	**20938**		1739	9.1%
No End Effects		2024 CC C	2032 Nuc	B02-C1	**9726**		-9473	-49.3%
Study Period 2012 - 2026		2021 CC C	2025 Nuc	B02-D1	**13394**		-5805	-30.2%
Gas Costs (Base Case: $4.00/mmBtu)								
Very Low	-$2.00/mmBtu	2028 CC	2033 Nuc	B02-S05L	**19008**		-191	-1.0%
Low	-$1.00/mmBtu	2028 CC	2033 Nuc	B02-I4	**19125**		-74	-0.4%
High	+$2.00/mmBtu	2027 CC	2032 Nuc	B02-I3	**19314**		115	0.6%
Very High	+$4.00/mmBtu	2024 CC C	2029 Nuc	B02-S05H	**19410**		211	1.1%
Coal Capacity Factors (85%); $0/Ton CO2								
Low	80%	2032 NC.J	2033 CC	B02-S03L	**15323**		90	0.6%
High	88%	2030 FC.J	2033 CC	B02-S03H	**15148**		-85	-0.6%
Pulverized Coal Capital Costs ($2,813/kW); $0/Ton CO2								
Very Low	$2,748 /kW	2030 FC.J	2033 CC	B02-S04L	**15083**		-150	-1.0%
Very High	$3,664 /kW	2032 NC.J	2033 CC	B02-S04H	**15508**		275	1.8%
Discount Rate (6.0%)								
High	12.0%	2028 CC	2033 Nuc	B02-S07H	**5286**		-13913	-72.5%
Nuclear, Capacity Factor (92%)								
Low	90%	2027 CC	2032 Nuc	B02-S02L	**19324**		125	0.7%
High	96%	2027 CC	2032 Nuc	B02-S02H	**19121**		-78	-0.4%
Fixed O&M		2027 CC	2032 Nuc	B02-N	**18986**		-213	-1.1%
Carbon Tax Legislation								
None - 0.0 $/ton CO2		2032 NC.J	2033 CC	B06-C01N	**15233**		-3966	-20.7%
Low - $7.0/ton, 2015		2027 CC	2032 Nuc	B06-C01L	**18598**		-601	-3.1%
Hgh - $21/ton, 2015		2024 CC C	2027 Nuc	B06-C01H	**19728**		529	3%

Attachment 17

Wind Energy Cases

"#" Column: if row is flagged, delta is from $0 CO2 BnchMrk

	Next Intermediate or Baseload		Case Name	NPV	#	Delta	%
Benchmark Cases (10% RPS - 400 MW)							
Base Case	2027 CC	2032 Nuc	B01	**19199**		Base	Base
$0/Ton CO2, 10% Wind, Benchmark	2032 NC.J	2033 CC	B06-C01N	**15233**		-3966	-20.7%
No Wind Beyond 2012	2027 CC	2032 Nuc	B05-N	**19341**		142	0.7%
No Wind Beyond 2012, $0/ton CO2	2030 FC.J	2033 CC	B05-NN	**15020**		-213	-1.1%
Wind 15 & 20 Percent RPS - 40% CF Wind							
15% RPS, 575 MW Wind	2028 CC	2032 Nuc	B05-15	**19102**		-97	-0.5%
20% RPS, 800 MW Wind	2028 CC	2033 Nuc	B05-20	**19029**		-170	-0.9%
10% RPS, High CO2	2024 CC C	2027 Nuc	B05-H	**19728**		529	2.8%
15% RPS, 575 MW Wind, High CO2	2024 CC C	2029 Nuc	B05-15H	**19517**		318	1.7%
20% RPS, 800 MW Wind, High CO2	2027 Nuc	2030 CC	B05-20H	**19140**		-59	-0.3%
10% RPS, Low CO2	2027 CC	2032 Nuc	B05-L	**18598**		-601	-3.1%
15% RPS, 575 MW Wind, Low CO2	2027 CC	2032 Nuc	B05-15L	**18639**		-560	-2.9%
20% RPS, 800 MW Wind, Low CO2	2027 CC	2033 CC	B05-20L	**18689**		-510	-2.7%
15% RPS, 575 MW Wind, $0/ton CO2	2032 FC.J	2033 CC	B05-15N	**15485**		252	1.3%
20% RPS, 800 MW Wind, $0/ton CO2	2032 NC.J	2033 CC	B05-20N	**15793**		560	2.9%
Base Case Schedule for Renewable Goal, Lower Wind Pricing, with and w/o CO2 Tax							
$50/MWh Wind	2027 CC	2032 Nuc	B08-L4	**19114**		-85	-0.4%
$45/MWh Wind	2027 CC	2032 Nuc	B08-L3	**19027**		-172	-0.9%
$42.5/MWh Wind	2027 CC	2032 Nuc	B08-L2	**18984**		-215	-1.1%
$50/MWh Wind, $0/Ton CO2	2032 NC.J	2033 CC	B08-L4N	**15148**		-85	-0.4%
$45/MWh Wind, $0/Ton CO	2032 NC.J	2033 CC	B08-L3N	**15062**		-171	-0.9%
$42.5/MWh Wind, $0/Ton CO2	2032 FC.J	2033 CC	B08-L2N	**15018**		-215	-1.1%
Meet Renewable Goal by End of 2015, Various Wind Pricing, with and w/o CO2 Tax							
$50/MWh Wind	2027 CC	2032 Nuc	B08-F4	**19128**		-71	-0.4%
$45/MWh Wind	2027 CC	2032 Nuc	B08-F3	**19038**		-161	-0.8%
$42.5/MWh Wind	2027 CC	2032 Nuc	B08-F2	**18994**		-205	-1.1%
Base Case Wind Cost	2027 CC	2032 Nuc	B08-F0	**19236**		37	0.2%
$50/MWh Wind, $0/Ton CO2	2032 NC.J	2033 CC	B08-F4N	**15184**		-49	-0.3%
$45/MWh Wind, $0/Ton CO	2032 NC.J	2033 CC	B08-F3N	**15094**		-139	-0.7%
$42.5/MWh Wind, $0/Ton CO2	2032 NC.J	2033 CC	B08-F2N	**15050**		-183	-1.0%
Base Case Wind Cost, $0/Ton CO2	2032 NC.J	2033 CC	B08-F0N	**15292**		59	0.3%

Attachment 18

Selected Cases - Expansion Plans

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

Case Name	OPPD 15 Year Plan B01	Benchmark Zero CO2 B06-CO1N	High Load Growth Base CO2 B02-S08H	15 % RPS Base CO2 B05-15	20 % RPS Base CO2 B05-20	15 % RPS Zero CO2 B05-15N	20 % RPS Zero CO2 B05-20N	CC in 2021 in leau of CT Base CO2 B01-GCC	Benchmark for retire Zero CO2 B07-FN	Retire N.O. 1-3 Zero CO2 B07-18N
^ NPV Cost	19,198,876	15,233,010	23,113,358	19,102,870	19,028,514	15,485,222	15,792,696	19,260,428	15,392,701	15,585,963
^ NPV Diff. from Benchmark	N/A	-3,965,866	3,914,482	-96,006	-170,362	252,212	559,686	61,552	N/A	193,262
% Diff. from Benchmark	N/A	-20.7%	20.4%	-0.5%	-0.9%	1.3%	2.9%	0.3%	N/A	1.0%

^ ($1,000's)

Expansion Plans: Year-by-Year Facilities through 2037, Note: Single Year Capacity Purchases Not Shown

Year										
2012										
2013	Cum Wind	Cum Wind	Cum Wind	Cum Wind	Cum Wind	Cum Wind	Cum Wind	Cum Wind	Cum Wind	Cum Wind
2014					Wind 80		Wind 80			
2015					Wind 80		Wind 80			
2016	Wind 20	Wind 20	Wind 20	Wind 80		Wind 80		Wind 20	Wind 20	Wind 20
2017	FC PU 75	FC PU 75	FC PU 75	FC PU 75 Wind 80	FC PU 75 Wind 80	FC PU 75 Wind 80	FC PU 75 Wind 80	FC PU 75	FC PU 75	FC PU 75 CT 160
2018	Wind 80	Wind 80	CT 160	Wind 80	Wind 80	Wind 80	Wind 80	Wind 80	Wind 80	Wind 80
2019				Wind 80	Wind 80	Wind 80	Wind 80	Wind 80		CT 160
2020	Wind 80	Wind 80	Wind 80		Wind 80		Wind 80	Wind 80	Wind 80	Wind 80
2021	CT160	CT 160	CT 160	CT 160 Wind 80	CT 160 Wind 80	CT 160 Wind 80	CT 160 Wind 80	CC 530	CT 160	
2022					Wind 80		Wind 80			
2023			CT 160							CT 160
2024	CT160	CT 160		CT 160	CT 160	CT 160	CT 160			
2025			CC 530							CT 160
2026	CT160									
2027	CC 530 Wind 80	CT 160 Wind 80	Wind 80	CT 160	CT 160 Wind 80	CT 160	CT 160 Wind 80	Wind 80	CT 160 Wind 80	CT 160
2028		CT 160		CC 530		CT 160	CT 160		CT 160	
2029				Wind 80		Wind 80		CT 160		Coal 300
2030		CT 160	Nuc 300				CT 160	Nuc 300	CT 160	
2031										
2032	Nuc 300	Coal 300				Coal 300	Coal 300		Coal 300	
2033	(2) Nuc 300	CC 530	CC 530 Nuc 300	(2) Nuc 300	(2) Nuc 300	CC 530	CC 530	(2) Nuc 300	CC 530	Coal 300 CC 530
2034			Nuc 300	Nuc 300	Nuc 300	Coal 300		CC 530		
2035	CT 160	Coal 300					Coal 300		Coal 300	
2036										
2037	CC 530	Coal 300		CC 530	CC 530	Coal 300	Coal 300		Coal 300	Coal 300

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 CO_2 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.