NP

2010-2029 Integrated Resource Plan
for
The Empire District Electric Company

Volume III
Supply-Side Resources Analysis (4 CSR 240-22.040)

September 2010

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S.0 Volume III Summary

This supply-side volume of Empire's 2010 Integrated Resource Plan (IRP) contains:

- information on Empire's existing resources including opportunities to upgrade or retire specific resources
- assumptions used for the optimization modeling and risk analysis
- the supply-side resources – both conventional and renewable – that were available for the model to consider in the optimization
- information on transmission system additions and associated smart grid plans
- the screening analysis with the resulting rankings used prior to resource modeling in the optimization models.

S.1 Existing Resources

Empire's existing resources to meet customer obligations include coal-fired units, natural gas-fired combustion turbines (CT), a hydroelectric facility, ownership shares in coal-fired units, an ownership share in a combined cycle (CC) unit, and long-term PPAs for coal and wind. Modifications and upgrades to Empire's existing units have occurred periodically in the past. Other modifications and upgrades are expected to occur in the future:

- Selective catalytic reduction equipment was installed in Asbury in 2008. In the future, it may be necessary to install additional air pollution control equipment at Asbury including a baghouse, scrubber, and powder activated carbon system (collectively referred to as the Asbury Air Quality Control System (AQCS)).
  ** ______________________________ **
- ** ______________________________ **
- When Riverton 12 was installed, adequate natural gas piping and transmission were designed and built to accommodate its conversion to a combined cycle unit at some point in the future. The potential Riverton 12 conversion to a combined cycle unit was considered as a candidate resource in this IRP.
- No major upgrades or environmental equipment are expected for either State Line or the Empire Energy Center units during the planning horizon.
- New water wheels were installed at Ozark Beach during the 2002-2004 time frame. If the U.S. Army Corps of Engineers implements the White River Reallocation Project, the amount of energy that Ozark Beach will provide in the future will be reduced.
- Empire's normal, ongoing maintenance program at each of its plants addresses critical operational and mechanical issues to ensure the longevity of the units.

S.2 Assumptions

A wide variety of data assumptions must be made for IRP modeling. These assumptions include fuel price forecasts, market price forecasts, capacity margin requirements, financial parameters, and emission costs. Parameters for generating resources, e.g., heat rates, operating and maintenance (O&M) costs, maintenance schedules, and forced outage rates, must also be specified. The load and energy forecast, an important series of assumptions, is described in Volume II.

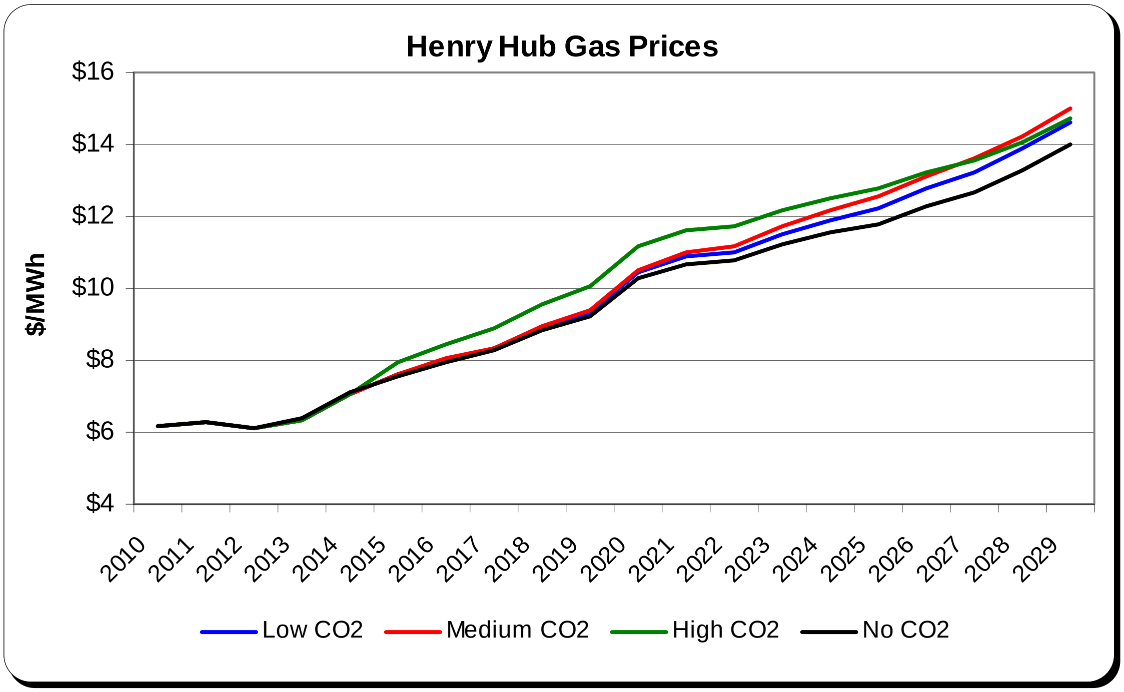
Two of the most significant assumptions underlying this IRP are the natural gas price assumptions and the costs for various forms of air emissions. These assumptions are shown in Table S-1, Figure S-1, and Table S-2. Four levels of carbon regulation, including a no carbon regulation case, were evaluated. Empire has assumed that if carbon regulation were implemented, it would be in the form of a cap and trade system.

Table S-1
Natural Gas Price Forecast ($/MMBtu)

Year	Base CO_2 Case	No CO_2 Case	Low CO_2 Case	High CO_2 Case
2010	6.16	6.16	6.16	6.16
2011	6.30	6.30	6.30	6.30
2012	6.12	6.13	6.12	6.12
2013	6.35	6.37	6.35	6.35
2014	7.07	7.11	7.07	7.07
2015	7.63	7.58	7.59	7.92
2016	8.03	7.95	7.98	8.47
2017	8.34	8.27	8.31	8.90
2018	8.94	8.84	8.90	9.58
2019	9.39	9.23	9.33	10.06
2020	10.49	10.29	10.45	11.19
2021	11.00	10.68	10.89	11.60
2022	11.17	10.78	11.00	11.70
2023	11.72	11.20	11.49	12.16
2024	12.17	11.55	11.90	12.51
2025	12.56	11.80	12.21	12.77
2026	13.13	12.28	12.77	13.22
2027	13.59	12.69	13.25	13.57
2028	14.23	13.29	13.89	14.06
2029	14.99	14.02	14.63	14.73

Source: Ventyx

Figure S-1



Source: Ventyx

Table S-2
Emissions Costs – Base Environmental

Year	SO_2 ($/ton)	NO_x ($/ton)	Hg ($000/ton)	CO_2 ($/ton)
2015	153	1,006	40,000	21.48
2016	162	1,035	40,000	24.12
2017	170	1,063	40,000	27.04
2018	177	1,090	40,000	30.09
2019	182	1,106	40,000	32.21
2020	186	1,120	40,000	34.66
2021	188	1,131	40,000	37.22
2022	188	1,131	40,000	40.19
2023	188	1,131	40,000	43.23
2024	188	1,131	40,000	46.87
2025	188	1,131	40,000	50.18
2026	188	1,131	40,000	53.90
2027	188	1,131	40,000	58.00
2028	188	1,131	40,000	62.35
2029	188	1,131	40,000	67.18

Source: Hg developed by Empire. Other costs developed by Ventyx

S.3 Conventional Future Supply-Side Resources

Empire considered a broad range of conventional resources as options for the future. These included: supercritical coal (ownership and power purchase agreement (PPA)), combustion turbine (CT), combined cycle (CC), nuclear (PPA only), distributed generation, and integrated gasification combined cycle (IGCC). To take advantage of economies of scale, Empire assumed that the nuclear option involved a PPA from a unit built by one or more other utilities in the region. The supercritical coal option was modeled as an ownership share of a unit built in the region. Combined cycle options included both new units as well as the conversion of Riverton 12 to a CC unit.

Resources using carbon capture and sequestration (CCS) were not assumed to be commercially viable within the planning horizon for the IRP. Parameters were developed for each of supercritical coal with CCS, combined cycle with CCS and IGCC with CCS and are presented in the tables containing data on each of the options. However, these resources were not options considered in the optimization modeling as they were not available during the twenty-year planning horizon of this IRP.

S.4 Renewable Future Supply-Side Resources

A range of potential renewable resources were considered as possible future supply-side resources. These included wind, landfill gas, biomass and solar thermal. Solar photovoltaics (PV) was considered as a demand-side option but did not pass the cost effectiveness screening and was therefore not considered further in the modeling.

S.5 Transmission and Smart Grid

Empire believes that at least some of the resources that will be required over the planning horizon may have significant transmission costs associated with them. Empire is a member of the Southwest Power Pool (SPP) and, as such, is now reliant on the SPP's determination of which transmission lines will be built and on what schedule. As a member of SPP, Empire is assigned a cost sharing allocation of all lines that are built in the SPP. That cost allocation varies per line.

The SPP conducts three studies directly associated with transmission planning: Large Generation Interconnect Studies, Aggregate Transmission Service Studies, and the SPP Transmission Expansion Plan (STEP). The Large Generation Interconnect Study determines all of the modifications needed to connect a new generator into the transmission system. The Aggregate Transmission Service Studies determine system upgrades required to grant transmission service from a generation source to a load. The STEP determines upgrades required for a reliable transmission system and provides a screening of potential economic projects. Until a specific line is submitted to the SPP, it is not possible to estimate what the actual cost to Empire will be. Therefore, Empire modeled a generic transmission cost adder for each alternative resource examined in this IRP.

As of January 2005, the SPP uses a Federal Energy Regulatory Commission (FERC)-approved process called an Aggregate Transmission Service Study. In this process, SPP combines all long-term point-to-point and all long-term network resource transmission service requests received during a sequential four-month open season into a single aggregate transmission service study. Such an aggregated analysis should result in a more optimal expansion of the SPP transmission system than occurred previously with less aggregated analyses.

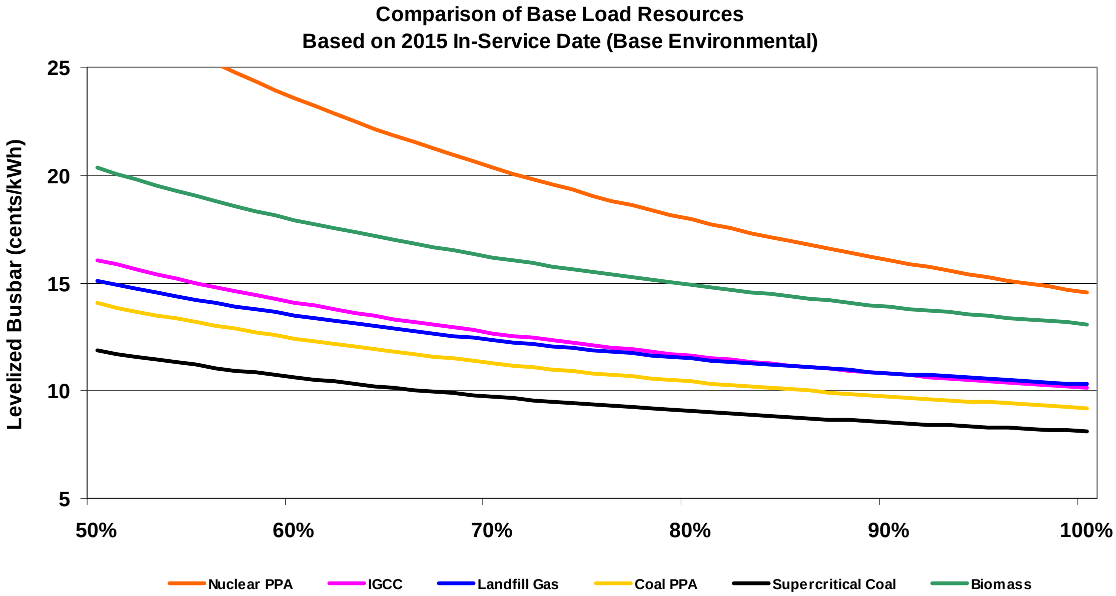
Empire actively participates in transmission planning in the SPP through committee membership, attending meetings, participation as a customer and a transmission owner in the development and implementation of SPP's transmission studies, and other methods. In two recent cases involving the Open Access Transmission Tariff in the SPP, Empire filed protests with the FERC. These cases involved the OATT "Highway/Byway" cost allocation methodology and the modified transmission planning process referred to as the Integrated Transmission Plan (ITP).

In March 2010, Empire assembled a team to develop a pilot program that would research and test the available metering products and technologies for an advanced metering infrastructure system such as would be required for Smart Grid. The main benefits of such a system are automated meter reading, on-demand meter reads, and instant outage notification. The proposed pilot program will include residential, commercial, and industrial customers, and will cover single-phase and three-phase applications. The plan is for the pilot program to implement two different communication technologies via two separate phases. The details of the pilot program are pending completion as this IRP was being finalized.

S.6 Screening Analysis

In accordance with the IRP supply-side rules, screening cost curves were developed under base environmental costs and probable environmental costs for baseload, intermediate, intermittent, and peaking resources (a total of eight screening cost curves). Rankings can be deduced by examination of those curves for any given capacity factor. As an example, the screening cost curve for baseload resources under the base environmental assumptions is presented in Figure S-2. Note that resources are compared for the capacity factors from 50% to 100% and that supercritical coal is the top resource across the entire range.

Figure S-2
Baseload Screening Curves – Base Environmental



Source: Venytx

1.0 Introduction

1.1 Background

The Empire District Electric Company (Empire) is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire's service territory includes an area of about 10,000 square miles with a population of over 450,000. The service territory is located principally in southwestern Missouri and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal activities of these areas include light industry, agriculture and tourism.

Empire's total 2009 retail electric revenues were derived approximately 89.1% from Missouri customers, 5.1% from Kansas customers, 3.0% from Oklahoma customers and 2.8% from Arkansas customers. Empire supplies electric service at retail to 120 incorporated communities and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity, with a regional population of approximately 157,000. Empire's system hit a new maximum hourly demand of 1,199 MW on January 8, 2010 during extreme cold weather. The previous maximum demand of 1,173 MW was set on August 15, 2007. Empire's 2009 native customer load was 5,263,206 MWh (net system input or NSI). Empire's electric operating revenues in 2009 were derived as follows: residential 41.6%, commercial 31.4%, industrial 15.2%, wholesale on-system 4.2%, wholesale off-system 3.3% and other 4.3%.

1.2 Regulatory Requirements

1.2.1 4 CSR 240-22.040 Supply-Side Resources Analysis

PURPOSE: This rule establishes minimum standards for the scope and level of detail required in supply-side resource analysis.

(1) The analysis of supply-side resources shall begin with the identification of a variety of potential supply-side resource options which the utility can reasonably expect to develop and implement solely through its own resources or for which it will be a major participant. These options include new plants using existing generation technologies; new plants using new generation technologies; life extension and refurbishment at existing generating plants; enhancement of the emission controls at existing or new generating plants; purchased power from utility sources, cogenerators or independent power producers; efficiency improvements which reduce the utility's own use of energy; and upgrading of the transmission and distribution systems to reduce power and energy losses. The utility shall collect generic cost and performance information for each of these potential resource options which shall include at least the following attributes where applicable:
(A) Fuel type and feasible variations in fuel type or quality;
(B) Practical size range;

(C) Maturity of the technology;
(D) Lead time for permitting, design, construction, testing and startup;
(E) Capital cost per kilowatt;
(F) Annual fixed operation and maintenance costs;
(G) Annual variable operation and maintenance costs;
(H) Scheduled routine maintenance outage requirements;
(I) Equivalent forced-outage rates or full and partial-forced-outage rates;
(J) Operational characteristics and constraints of significance in the screening process;
(K) Environmental impacts, including at least the following:
1. Air emissions including at least the primary acid gases, greenhouse gases, ozone precursors, particulates and air toxics;
2. Waste generation including at least the primary forms of solid, liquid, radioactive and hazardous wastes;
3. Water impacts including direct usage and at least the primary pollutant discharges, thermal discharges and groundwater effects; and
4. Siting impacts and constraints of sufficient importance to affect the screening process; and

(L) Other characteristics that may make the technology particularly appropriate as a contingency option under extreme outcomes for the critical uncertain factors identified pursuant to 4 CSR 240-22.070(2).

(2) Each of the supply-side resource options referred to in section (1) shall be subjected to a preliminary screening analysis. The purpose of this step is to provide an initial ranking of these options based on their relative annualized utility costs as well as their probable environmental costs and to eliminate from further consideration those options that have significant disadvantages in terms of utility costs, environmental costs, operational efficiency, risk reduction or planning flexibility, as compared to other available supply-side resource options. All costs shall be expressed in nominal dollars.

(A) Cost rankings shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the resource using the utility discount rate. In lieu of levelized cost, the utility may use an economic carrying charge annualization in which the annual dollar amount increases each year at an assumed inflation rate and for which a stream of these amounts over the life of the resource yields the same present value.

(B) The probable environmental costs of each supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental laws or regulations that may be imposed at some point within the planning horizon.
1. The utility shall identify a list of environmental pollutants for which, in the judgment of utility decision-makers, additional laws or regulations may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.
2. For each pollutant identified pursuant to paragraph (2)(B)1., the utility shall specify at least two (2) levels of mitigation that are more stringent than

existing requirements which are judged to have a nonzero probability of being imposed at some point within the planning horizon.

3. For each mitigation level identified pursuant to paragraph (2)(B)2., the utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that additional laws or regulations requiring that level of mitigation will be imposed at some point within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation level for each identified pollutant.
4. The probable environmental cost for a supply-side resource shall be estimated as the joint cost of simultaneously achieving the expected level of mitigation for all identified pollutants emitted by the resource. The estimated mitigation costs for an environmental pollutant may include or may be entirely comprised of a tax or surcharge imposed on emissions of that pollutant.

(C) The utility shall rank all supply-side resource options identified pursuant to section (1) in terms of both of the following cost estimates: utility costs and utility costs plus probable environmental costs. The utility shall indicate which supply-side options are considered to be candidate resource options for purposes of developing the alternative resource plans required by 4 CSR 240- 22.060(3). The utility shall also indicate which options are eliminated from further consideration on the basis of the screening analysis and shall explain the reasons for their elimination.

(3) The analysis of supply-side resource options shall include a thorough analysis of existing and planned interconnected generation resources. The analysis can be performed by the individual utility or in the context of a joint planning study with other area utilities. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the supply resource options under consideration, that the costs of transmission system investments associated with supply-side resources are properly considered and to provide an adequate foundation of basic information for decisions about the following types of supply-side resource alternatives:

(A) Joint participation in generation construction projects;
(B) Construction of wholly-owned generation or transmission facilities; and
(C) Participation in major refurbishment, upgrading or retrofitting of existing generation or transmission resources.

(4) The utility shall identify and analyze opportunities for life extension and refurbishment of existing generation plants, taking into account their current condition to the extent that it is significant in the planning process.

(5) The utility shall identify and evaluate potential opportunities for new long-term power purchases and sales, both firm and nonfirm, that are likely to be available over all or part of the planning horizon. This evaluation shall be based on an analysis of at least the following attributes of each potential transaction:

(A) Type or nature of the purchase or sale (for example, firm capacity, summer only);
(B) Amount of power to be exchanged;
(C) Estimated contract price;
(D) Timing and duration of the transaction;
(E) Terms and conditions of the transaction, if available;

(F) Required improvements to the utility's generating system, transmission system, or both, and the associated costs; and
(G) Constraints on the utility system caused by wheeling arrangements, whether on the utility's own system, or on an interconnected system, or by the terms and conditions of other contracts or interconnection agreements.

(6) For the utility's preferred resource plan selected pursuant to 4 CSR 240-22.070(7), the utility shall determine if additional future transmission facilities will be required to remedy any new generation-related transmission system inadequacies over the planning horizon. If any such facilities are determined to be required and, in the judgment of utility decision-makers, there is a risk of significant delays or cost increases due to problems in the siting or permitting of any required transmission facilities, this risk shall be analyzed pursuant to the requirements of 4 CSR 240-22.070(2). [CLARIFICATION PROVIDED]

(7) The utility shall assess the age, condition and efficiency level of existing transmission and distribution facilities, and shall analyze the feasibility and cost-effectiveness of transmission and distribution system loss-reduction measures as a supply-side resource. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution system, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options. [CLARIFICATION PROVIDED]

Table 1-1
Clarification– Transmission and Distribution Planning

Applies to: **4 CSR 240-22.040 (6)** **4 CSR 240-22.040 (7)**
The existing IRP Rule predates the current Southwest Power Pool, Inc regional transmission organization's (SPP RTO) transmission planning process and does not contemplate such an organization. SPP conducts three studies directly associated with transmission planning: Large Generation Interconnection Studies, Aggregate Transmission Service Studies, and the SPP Transmission Expansion Plan. Empire actively participates, as a customer and transmission owner, in the development and implementation of all of the transmission studies conducted by SPP. In addition, Empire is continually monitoring the distribution system and looking for cost effective ways to maintain and improve the distribution system. Empire will provide a section outlining the SPP transmission planning processes and the extent of Empire's participation in these processes in its upcoming IRP filing. The distribution system maintenance and improvements that are under consideration will also be described in the IRP report. The results of the studies and the impacts on Empire will also be summarized. Like Empire's last IRP filing, the SPP Expansion Plan projects and Empire's most current Transmission and Distribution Construction Budget will be provided as appendices to the Supply-Side Resource Analysis report.

(8) Before developing alternative resource plans and performing the integrated resource analysis, the utility shall develop ranges of values and probabilities for several important uncertain factors related to supply resources. These values can also be used to refine or verify information developed pursuant to section (2) of this rule. These

cost estimates shall include at least the following elements and shall be based on the indicated methods or sources of information:

(A) Fuel price forecasts over the planning horizon for the appropriate type and grade of primary fuel and for any alternative fuel that may be practical as a contingency option.

1. Fuel price forecasts shall be obtained from a consulting firm with specific expertise in detailed fuel supply and price analysis or developed by the utility if it has expert knowledge and experience with the fuel under consideration. Each forecast shall consider at least the following factors as applicable to each fuel under consideration:
   A. Present reserves, discovery rates and usage rates of the fuel and forecasts of future trends of these factors;
   B. Profitability and financial condition of producers;
   C. Potential effect of environmental factors, competition and government regulations on producers, including the potential for changes in severance taxes;
   D. Capacity, profitability and expansion potential of present and potential fuel transportation options;
   E. Potential effects of government regulations, competition and environmental legislation on fuel transporters;
   F. In the case of uranium fuel, potential effects of competition and government regulations on future costs of enrichment services and cleanup of production facilities; and
   G. Potential for governmental restrictions on the use of the fuel for electricity production.
2. The utility shall consider the accuracy of previous forecasts as an important criterion in selecting providers of fuel price forecasts.
3. The provider of each fuel price forecast shall be required to identify the critical uncertain factors that drive the price forecast and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty;

(B) Estimated capital costs including engineering design, construction, testing, startup and certification of new facilities or major upgrades, refurbishment or rehabilitation of existing facilities.

1. Capital cost estimates shall either be obtained from a qualified engineering firm actively engaged in the type of work required or developed by the utility if it has available other sources of expert engineering information applicable to the type of facility under consideration.
2. The provider of the estimate shall be required to identify the critical uncertain factors that may cause the capital cost estimates to change significantly and to provide a range of estimates and an associated subjective probability distribution that reflects this uncertainty;

(C) Estimated annual fixed and variable operation and maintenance costs over the planning horizon for new facilities or for existing facilities that are being upgraded, refurbished or rehabilitated.

1. Fixed and variable operation and maintenance cost estimates shall be obtained from the same source that provides the capital cost estimates.
2. The critical uncertain factors that affect these cost estimates shall be identified and a range of estimates shall be provided, together with an associated subjective probability distribution that reflects this uncertainty;

(D) Forecasts of the annual cost or value of sulfur dioxide emission allowances to be used or produced by each generating facility over the planning horizon.

1. Forecasts of the future value of emission allowances shall be obtained from a qualified consulting firm or other source with expert knowledge of the factors affecting allowance prices.
2. The provider of the forecast shall be required to identify the critical uncertain factors that may cause the value of allowances to change significantly and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty; and

(E) Annual fixed charges for any facility to be included in rate base or annual payment schedule for leased or rented facilities.

(9) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall furnish at least the following information:

(A) A summary table showing each supply resource identified pursuant to section (1) and the results of the screening analysis, including:

1. The calculated values of the utility cost and the probable environmental cost for each resource option and the rankings based on these costs;
2. Identification of candidate resource options that may be included in alternative resource plans; and
3. An explanation of the reasons why each supply-side resource option rejected as a result of the screening analysis was not included as a candidate resource option;

(B) A list of the candidate resource options for which the forecasts, estimates and probability distributions described in section (8) have been developed or are scheduled to be developed by the utility's next scheduled compliance filing pursuant to 4 CSR 240-22.080;

(C) A summary of the results of the uncertainty analysis described in section (8) that has been completed for candidate resource options; and

(D) A summary of the mitigation cost estimates developed by the utility for the candidate resource options identified pursuant to subsection (2)(C). This summary shall include a description of how the alternative mitigation levels and associated subjective probabilities were determined and shall identify the source of the cost estimates for the expected mitigation level.

Table 1-2 documents how the reporting requirements for 4 CSR 240-22.040, the IRP Rules for Supply-Side Resource Analysis, have been addressed.

Table 1-2
Summary of Compliance with Reporting Requirements for IRP Rule for Supply-Side Resource Analysis (4 CSR 240-22.040 (9))

Rule	Description	Location in Report
22.040 (9) (A)	Summary table requirements	Tables 7-1 through 7-10
22.040 (9) (B)	Candidate resource options	Section 4.0 and Section 5.0
22.040 (9) (C)	Results of uncertainty analysis	Volume V
22.040 (9) (D)	Summary of mitigation costs	Emission rates – Section 4.0 Allowance Costs – Section 3.0

1.2.2 Followup to the 2007 IRP Unanimous Stipulation and Agreement (dated May 6, 2008)

In the 2007 IRP Unanimous Stipulation and Agreement dated May 6, 2008, Empire agreed to undertake the following tasks related to supply-side resource analysis prior to or as a part of its next IRP filing:

- Any costs not listed separately shall be identified with documentation that those costs are included in the total costs.
- Consider and analyze upgrades to all existing plant and detail that analysis.
- Cost rankings for supply-side resources will be provided unless Empire is granted a waiver from this requirement or there is a change in this part of the IRP rule.
- Consider other long-term PPAs [in addition to wind] as candidate resources.
- Identify critical uncertain factors for annual fixed and variable operation and maintenance costs, describe why these costs were or were not deemed critical factors unless Empire is granted a waiver from this requirement or there is a change in this part of the IRP rule.
- Analyze dispatchable renewable resources such as landfill gas generation and additional biomass technologies; solar-based non-dispatchable renewable technologies such as photovoltaic (PV) and solar thermal generation resources; and potential energy efficiency improvements of existing resources.
- If any resource options are eliminated during the screening phase, the Company will provide an explanation of the process used to eliminate it.

Table 1-3 provides the location in this volume or in another volume of this IRP in which a specific portion of the requirements from the 2007 IRP Unanimous Stipulation and Agreement has been addressed.

Table 1-3
Summary of Compliance with the Requirements of the 2007 IRP Unanimous Stipulation and Agreement

S&A Issue – Brief Description	Location in Report
Costs not identified separately to be documented as being in the total costs	Sections 3.0, 4.0 and 5.0
Document analysis of consideration of upgrades for existing plants	Section 2.1.11
Cost rankings for supply-side resources	Tables 7-1 through 7-10
Long-term PPAs in addition to wind considered as possible resources	Section 4.0 – Coal PPA and Nuclear PPA
Critical uncertain factors for annual fixed and variable O&M costs	Section 4.0 and Volume V
Analyze dispatchable renewable resources such as landfill gas and biomass	Section 5.2.2
Analyze solar-based non-dispatchable such as PV and solar thermal	Section 5.2.3 and Volume IV (solar PV as a DSM resource)
Analyze potential energy efficiency improvements of existing resources	Section 6.1
Explanation for any resource options eliminated during a screening phase	Section 4.1, Section 4.3

2.0 Existing and Committed Supply-Side Resources

The existing supply-side resources described in this IRP include those conventional and renewable resources that are in operation on the Empire system or for which Empire has power purchase agreements (PPA). Committed resources include those conventional and renewable resources for which commitments have already been made. Existing and committed as well as future resources were examined in the modeling process for this IRP.

2.1 Existing Resources

Empire's existing resources to meet customer obligations include coal-fired units, natural gas-fired combustion turbines (CT), a hydroelectric facility, ownership shares in coal-fired units, an ownership share in a combined cycle (CC) unit, and long-term PPAs for coal and wind. These resources are summarized on Table 2-1. All unit ratings and environmental retrofit information described in this IRP represent ratings and assumptions in effect at the time the IRP was in the process of being completed. Units are rerated from time to time and all assumptions are subject to change.

In 2009, 54.5% of Empire's total system input (in kWh) was supplied by its steam and thermal generation units, 1.5% was supplied by its hydroelectric generation, and the remaining 44% was purchased power, including wind energy. As also shown on Figure 2-1, coal-fired energy purchased from others under contract constituted 18.6% of Empire's 2009 energy profile and wind energy purchases amounted to 15%.

Figure 2-1
2009 Energy Provision by Fuel Type

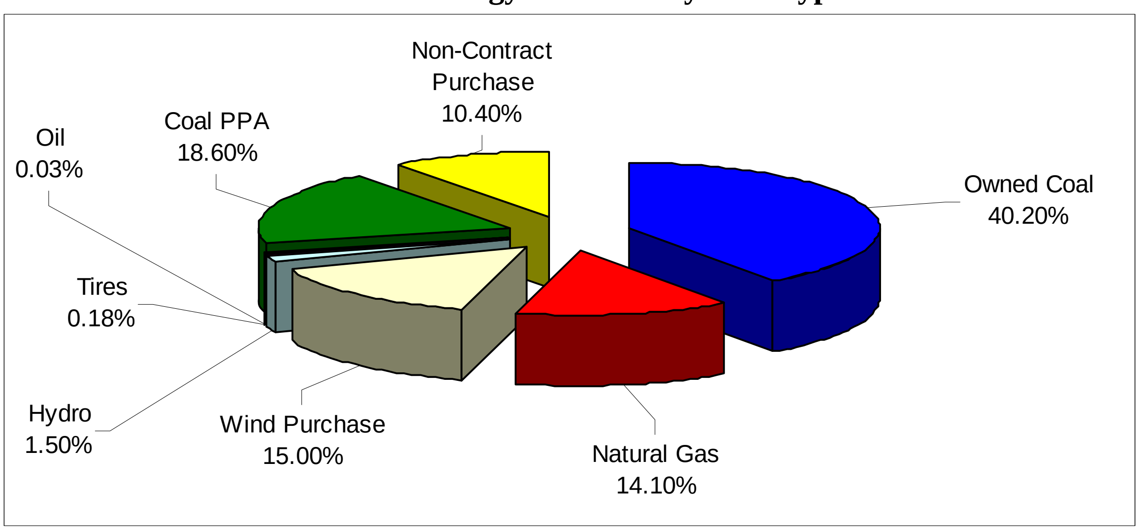


Table 2-1
Empire Supply-Side Resources – Existing and Committed

Power Plant	Fuel Type	State	Interest (%)	Empire Capacity (MW)	Start Date	Facility Age (Years)
Asbury 1 & 2	Coal	MO	100	207	1970 & 1986	40 & 24
Riverton 7 & 8	Coal	KS	100	92[1]	1950 & 1954	60 & 56
Iatan 1	Coal	MO	12	85	1980	30
Iatan 2[2]	Coal	MO	12	102	2010	<1
Plum Point	Coal	AR	7.52	50	2010	<1
Riverton CTs (9-12)[3]	Natural Gas	KS	100	194	1964, 1988, 1988 & 2007	46, 22, 22, & 3
Empire Energy Center CTs	Natural Gas/Oil	MO	100	267	1978 & 1981 2003 & 2003	32 & 29 7 & 7
State Line CT	Natural Gas/Oil	MO	100	96	1995	15
State Line CC	Natural Gas	MO	60	300[4]	1997 &2001[5]	13 & 9
Ozark Beach	Hydro	MO	100	16	1913	97
Total Empire Installed Capacity				1,409		
Long Term Power Purchases	**Type**				**End Date**	**Term**
Plum Point	Coal			50	2015[8]	
Elk River Windfarm (150 MW PPA)	Wind			7[6]	2025[6]	20[6]
Meridian Way Wind Farm (105 MW PPA)	Wind			8[7]	2028[7]	20[7]
Capacity Summary						
Total Coal				536		
Total Gas Turbine				557		
Total Combined Cycle				300		
Total Hydro				16		
Total Purchase including Wind				65		
TOTAL				1,474		

[1]Riverton 7 is rated at 38 MW, but can produce about 25 MW when solely burning coal. Riverton 8 is rated at 54 MW, but can produce about 45 MW when solely burning coal. Both units achieve the remainder of the capacity by over-firing natural gas.
[2]Iatan 2 is characterized as a committed unit. It is expected to enter commercial operation Fall of 2010.
[3]Riverton 10 and 11 were manufactured in 1967 but were installed at Empire in 1988; they are 43 years old.
[4]Represents Empire's 60% share of a 500 MW State Line Combined Cycle (SLCC) unit.
[5]One of the gas turbines at State Line CC was installed in 1997 and hence is 13 years old. The other gas turbine and the steam turbine were installed in 2001.
[6]The Elk River Windfarm consists of 100 1.5 MW turbines for a total of 150 MW. For purposes of the IRP, 7 MW of its installed capacity is counted toward the Company's reserve margin. Although the term of the PPA is 20 years, the term can be extended once for a period of 5 years at Empire's option.
[7]The Meridian Way Windfarm began commercial operation on December 15, 2008. The facility is rated at 105 MW and approximately 8 MW is counted toward the Company's reserve margin.
[8]Empire owns an undivided ownership interest of 7.52% (approximately 50 MW) in Plum Point and has signed a PPA for an additional 50 MW. Empire has the right to convert the PPA to an undivided ownership interest in 2015.

2.1.1 Asbury

The Asbury plant, located near Asbury, Missouri consists of two coal-fired units totaling 207 MW. Unit 1 was installed in 1970. Unit 2 was installed in 1986.

Many modifications have been made to the Asbury plant since Unit 1 achieved commercial operation in 1970. The precipitators were upgraded in 1977. The generator was rewound in 2007. A new state-of-the-art coal unloading facility was completed in 1990. In 1999, a new cooling tower was installed – the new fiberglass tower replaced the previous wood one. The cyclones were replaced in 2001, after they had operated for 30 years. Also in 2001, a distributed control system was installed. Selective catalytic reduction (SCR) for nitrous oxides (NO_x) control was completed in 2008; equipment to overfire air (also for NO_x control) was installed in 2001 and 2004. Routine maintenance, annual maintenance, and long-term maintenance is conducted on each of the units reflecting short-term and long-term cycles. As an example, the turbines are torn down approximately every 5-6 years (depending on hours of operation and the number of starts) and blades are replaced periodically as necessary. **____**

In the future, it may be necessary to install additional pollution control equipment (referred to as Air Quality Control System (AQCS)) at the Asbury station for compliance with regulations relating to SO_2, particulates and mercury. During the period of time that the IRP was being prepared, studies were being conducted by Black & Veatch and analysis was conducted in the IRP modeling to examine the economic desirability of installing the AQCS at Asbury versus retiring the plant. The AQCS equipment being examined included a scrubber, baghouse and powder activated carbon system.
____

In anticipation of potential regulation for ash ponds being issued in the future, Empire has also been examining the need for a new ash landfill and a bottom ash conveyance system. A study is being performed by Aquaterra. The equipment required and the costs for implementation have been identified for this IRP.

2.1.2 Riverton

Empire's Riverton generating plant located at Riverton, Kansas, has two steam-electric generating units (Riverton 7 and 8) with an aggregate generating capacity of 92 MW and four natural gas-fired combustion turbine units (Riverton 9, 10, 11 and 12) with an aggregate generating capacity of 194 MW. Riverton 7 is rated at 38 MW, but can only produce about 25 MW when solely burning coal. The remainder of the capacity is achieved by over-firing natural gas. Riverton 8 is rated at 54 MW, but can produce about 45 MW when solely burning coal. The remainder of the capacity is achieved by over-firing natural gas.

Riverton 7 and 8 burn a blend of coal and petroleum coke. The units all have their original control systems. Precipitators were installed in 1976 for dust and particulate control.

Riverton 9 (12 MW and currently 46 years old) is capable of burning oil in addition to natural gas and is permitted such that it can burn oil. The operation of Riverton units 9 and Riverton 7 are linked. Riverton 10 and 11 (installed in 1988) have the capability to burn oil but under their permit may only do so under emergency conditions. Riverton 10 and 11 both have black start capability.

Routine maintenance is performed on all units. The units are inspected at regular intervals and teardowns occur according to the manufacturers' recommendations. When Riverton 12 was installed in 2007, adequate natural gas piping and transmission were designed and built to accommodate its conversion to a combined cycle unit at some point in the future. Riverton 12's summer rating is currently 150 MW. If Riverton 12 were converted to a combined cycle unit, the CC rating would be a total of 250 MW, representing an addition of 100 MW. The conversion of Riverton 12 to a CC from a CT is a candidate resource in this IRP. **________________________________**

**________________________________

________________________________** is driven by requirements for the U.S. Environmental Protection Agency (EPA) to promulgate final standards addressing mercury and other hazardous air pollutants by November 2011. The mercury standards must delineate maximum achievable control technology (MACT). If the EPA does not meet the requirement to promulgate rules by 2012, all existing units will need to meet a 90% MACT standard by 1/1/2015. The 90% MACT standard would **________________________________**

2.1.3 Iatan 1

Empire owns a 12% undivided interest in the nominal 670 MW coal-fired Iatan 1 located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. Empire is entitled to

12% of the unit's available capacity and is obligated to pay for that percentage of the operating costs of the unit.

AQCS additions at Iatan 1 included an SCR for the removal of NO_x, a wet scrubber for the removal of sulfur dioxides (SO_x), a fabric filter baghouse for the removal of particulate matter, and a powder-activated carbon system for the removal of mercury. These additions, made in order to comply with U.S. Environmental Protection Agency regulations and to meet the requirements for an air permit for Iatan 2, were completed on April 19, 2009.

2.1.4 State Line

Empire's State Line Power Plant, located west of Joplin, Missouri, presently consists of State Line Unit 1, a CT with generating capacity of 96 MW and a CC unit (State Line CC) with generating capacity of 500 MW, of which Empire is entitled to 60%, or 300 MW. All units at the State Line Power Plant burn natural gas as a primary fuel, with State Line Unit 1 having the ability to also burn fuel oil as a backup fuel. Burning fuel oil requires water injection. The combined cycle consists of two CTs with a heat recovery steam generator (HRSG) on the back of each CT. Steam from the HRSGs is fed to the steam turbine. The CC can operate in two modes: 1) 1 x 1 mode (one CT and the steam turbine) with capacity of 150 MW (Empire's share) and 2) 2 x 1 mode (two CTs and the steam turbine) with total capacity of 300 MW (Empire's share). The total State Line CC heat rate is roughly 7,400 Btu/kWh.

No major upgrades or additional environmental equipment are expected for any unit at the State Line facility during the planning horizon. Routine maintenance will be conducted. The SLCC CTs have dry low NO_x burners and there is an SCR on each HRSG.

2.1.5 Empire Energy Center

Empire has four CT peaking units at the Empire Energy Center in Jasper County, Missouri (near the town of La Russell), with an aggregate generating capacity of 267 MW. Energy Center units 1 and 2 were installed in 1978 and 1981. They are simple cycle frame CTs. Energy Center units 3 and 4 are aeroderivative CTs installed in 2003. These two newer units have the ability to be on line in ten minutes or less and are thus considered quick start units.

These peaking units operate on natural gas as well as fuel oil. These units do not require water injection when they burn fuel oil. All units undergo routine maintenance with inspections on a regular cycle and equipment is refurbished as needed. All of the CTs use water injection to control NO_x.

2.1.6 Ozark Beach

Empire's hydroelectric generating plant, located on the White River at Ozark Beach, Missouri, has a generating capacity of 16 MW (four 4 MW units). This facility entered operation in 1913 and will shortly be 100 years old.

New water wheels were installed at Ozark Beach in the 2002-2004 timeframe. In this IRP, the energy available from Ozark Beach was reduced in every year starting in 2011 to reflect the energy lost from the reallocation of water in the White River by the U.S. Army Corps of Engineers.

2.1.7 Plum Point

The Plum Point Energy Station, a new 665-MW, sub-critical coal-fired generating facility being built near Osceola, Arkansas met in-service criteria on August 12, 2010 and has since been declared to be in commercial operation. Empire owns 7.52% (approximately 50 MW) of the project. In addition, Empire has a 30-year PPA for an additional 50 MW of capacity and an option to purchase an undivided ownership share of the 50 MW covered by the PPA in 2015.

Plum Point is equipped with an SCR for NO_x removal, a dry scrubber for SOx control, combustion controls for Volatile Organic Compounds (VOC) mitigation, and a fabric filter baghouse for the removal of particulate matter.

2.1.8 Purchased Power

Empire has existing PPAs for both conventional and renewable resources during the planning horizon.

2.1.8.1 Conventional

During the first part of 2010, Empire purchased power under a PPA with Westar Energy. The capacity and energy purchased under this contract were provided from the three coal-fired generating units at Westar's Jeffrey Energy Center. This contract was for 162 MW of capacity and energy. It expired on May 31, 2010.

In addition to its undivided ownership share of 7.52% (approximately 50 MW) in the Plum Point Energy Station, Empire entered into a PPA for an additional approximate 50 MW of capacity. Empire has the option to convert this PPA into an undivided ownership interest of approximately 50 MW in 2015.

During 2010, Empire entered into a short-term PPA with Merrill Lynch for 41 MW over a four-month period to help meet its summer peak demand. It expires September 30, 2010.

2.1.8.2 Renewables

On December 10, 2004, Empire entered into a 20-year contract with PPM Energy to purchase all of the energy generated at the Elk River Windfarm located in Butler County, Kansas. The Windfarm began commercial operation on December 15, 2005. This facility consists of 100 1.5 MW turbines. Empire also has the ability to extend the contract term for five years after the end of the 20-year contract period. Empire has contracted to purchase all of the output of the project which is estimated to be approximately 550,000 MWh of energy per year. For purposes of the IRP, 7 MW of the 150 MW of installed capacity is counted toward the Company's reserve margin. This is the actual current rating of the facility calculated per SPP criteria.

In June 2007, Empire signed a contract with Horizon Wind Energy to buy wind energy from the Cloud County Wind Farm, LLC which receives energy from the 105 MW Meridian Way Wind Farm located in Cloud County, Kansas near Concordia. The facility is expected to generate approximately 350,000 MWh per year. The facility began commercial operation on December 23, 2008. For purposes of the IRP, 8 MW of the 105 MW of installed capacity is counted toward the Company's reserve margin. This is the actual current rating of the facility calculated per SPP criteria.

2.1.9 Retirements

Empire's generating resources as shown in Table 2-1 include units that have been in operation for over 50 years. During the process of preparing this IRP, each plant manager and the Director of Environmental Services was interviewed. Topics covered during each interview included the age of the units, the maintenance schedule, known environmental requirements and effects of such on the units, and the ability to place additional generation at the plant site.

Barring significant changes in environmental regulations at the state or federal level, retirements of units **______________________________** over the planning horizon would occur only in the case of a catastrophic equipment failure where it would not be economically feasible for the unit to continue operation.

2.1.10 Emission Controls on Existing Units

Outside of this IRP but concurrently, Empire hired Black & Veatch to examine the cost effectiveness of installing AQCS equipment on the Asbury plant in 2015. That analysis had not been completed at the time of the IRP filing although preliminary numbers were available for use in the IRP.

2.1.11 Existing Plant Upgrades

An examination of recent and possible upgrades at existing plants was conducted by Empire during the development of this IRP.

- New pollution control systems have recently been installed at the coal-fired Asbury and Iatan 1 units. Asbury was retrofitted with an SCR. A scrubber, SCR, and powder activated carbon system were installed at the jointly-owned Iatan unit 1 coal-fired unit.
- Both coal units that are expected to be in service in 2010 (Plum Point and Iatan 2) have environmental control equipment.
- A study was underway in 2010 to determine the costs and construction timeline associated with the Asbury AQCS.
- The possible conversion of Riverton Unit 12 (a combustion turbine) to a combined cycle unit is one of the potential supply-side resource options evaluated in this IRP.
- The plant managers and environmental staff were interviewed and discussed any potential changes to the generating facilities expected during the planning horizon.
- Empire installed new water wheels at the Ozark Beach hydroelectric facility during 2002-2004. This plant upgrade resulted in an average increased output as compared to the old wheels of over 16% in the 20 to 50 feet of net head range, with some net head points being well above the overall average increase.
- Empire's normal, ongoing maintenance program at each of its plants addresses critical operational and mechanical issues to ensure the longevity of the units.

2.2 Committed Resources

Empire entered into a letter of intent with Kansas City Power & Light (KCP&L) on June 10, 2005, with respect to Empire's potential purchase of an undivided ownership interest in the proposed 850 MW supercritical coal-fired Iatan 2. Subsequently, a joint ownership contract was signed. This contract, announced in June 2006, provides for Empire's 12% ownership participation, approximately 102 MW of generation capacity, and a proportionate share of the construction, operation, and maintenance costs. At present, Empire expects the Iatan 2 unit to be commercial in the Fall of 2010.

After accounting for all existing resources (including deratings and retirements) and all planned resources, Empire faces a resource deficit around the **_____________** based on the base load forecast for this IRP as shown in Table 2-2 and Figure 2-2. As part of Empire's normal budget cycle, an updated five-year load forecast has been developed. As a result of the new five-year load forecast (September 2010), Empire believes that the **____**.

Figure 2-2
Load and Capability Summary
****Highly Confidential in its Entirety****

Table 2-2
Load and Capacity Summary 2010-2029 with Existing Resources, Committed Resources and Potential Retirements and Contract Expirations with Base Load Forecast for this IRP and no Contemplated Additions (MW)
****Highly Confidential in its Entirety****

3.0 Assumptions

A wide variety of data assumptions must be made for IRP modeling. Many of these assumptions are described in the following paragraphs and include fuel price forecasts, market price forecasts, capacity margin requirements, financial parameters, and emission costs. Parameters for generating resources, e.g., heat rates, operating and maintenance (O&M) costs, maintenance schedules, and forced outage rates, must also be specified. The load and energy forecast, an important series of assumptions, is described in Volume II.

3.1 Fuel Usage

Table 3-1 shows a comparison of historical fuel costs, including transportation and other fuel-related costs, for Empire's facilities:

Table 3-1
Empire's Historical Delivered Fuel Costs ($/MMBtu)

Fuel Type	2009	2008	2007
Coal - Iatan	1.186	1.070	0.978
Coal - Asbury	1.763	1.577	1.432
Coal – Riverton	1.768	1.724	1.548
Natural Gas	7.376	6.909	7.050
Oil	14.318	16.721	14.870

Empire's weighted cost of fuel burned per kWh generated was 3.1698 cents in 2009, 3.1307 cents in 2008, and 3.2197 cents in 2007.

The Asbury Plant is fueled primarily by coal with oil being used as the start-up fuel and tire-derived fuel (TDF) being used as a supplemental fuel. In 2009, Asbury burned a coal blend consisting of approximately 86.8% Western coal (referred to in this report as either Western or Powder River Basin – PRB coal) and 13.2% local coal (so-called blend coal) on a tonnage basis. Since Empire began burning TDF at Asbury, the equivalent of nearly 4.5 million passenger tires has been consumed as fuel.

The Riverton Plant fuel requirements are primarily met by coal with the remainder supplied by natural gas, petroleum coke, and oil. A Siemens V84.3 A2 combustion turbine (Unit 12) was installed at the Riverton plant in 2007. Riverton 12 and three other smaller units are fueled by natural gas. During 2009, Riverton Units 7 and 8 burned an estimated blend of approximately 82.1% Western coal and 17.9% petroleum coke on a tonnage basis.

All of the Western coal for Asbury and Riverton Units 7 and 8 is shipped to the Asbury Plant by rail, a distance of approximately 800 miles. The Western coal is transported from Asbury to Riverton via truck. Both local coal and petroleum coke are transported to Riverton and Asbury via truck.

Unit 1 at the Iatan Plant is a jointly-owned coal-fired generating unit. Empire's ownership share is 12% (approximately 85 MW). KCP&L is the operator of this plant and is responsible for arranging its fuel supply. The PRB coal burned in Iatan 1 is transported by rail by the Burlington Northern and Santa Fe (BNSF) Railway Company.

The coal-fired Plum Point Energy Station met the in-service criteria on August 12, 2010. Empire owns, through an undivided interest, 7.52% (approximately 50 MW) of the project's capacity. Empire has entered into a capital lease for railcars to provide the coal for this facility. Empire also has a long-term power purchase agreement (PPA) for an additional 50 MW from this facility.

The Energy Center and State Line simple cycle combustion turbine facilities are fueled primarily by natural gas with fuel oil available for use as needed. During 2009, fuel consumption at the Energy Center was 99.8% natural gas on a kWh generated basis. Essentially all of the State Line unit 1 generation came from natural gas in 2009. The SLCC unit is fueled 100% by natural gas.

Empire has firm transportation agreements with Southern Star Central Pipeline, Inc. for the transportation of natural gas to the State Line Power Plant for the jointly-owned combined cycle unit. This transportation agreement can also supply natural gas to State Line Unit No. 1, the Energy Center or the Riverton Plant, as elected by Empire on a secondary basis. In 2002, Empire signed a precedent agreement with Williams Natural Gas Company (now Southern Star Central), that provides additional transportation market zone capability through 2022. This contract provides firm market zone transport to the sites that previously were only served on a secondary basis. The majority of Empire's physical natural gas supply requirements will be met by short-term forward contracts and spot market purchases. Forward natural gas commodity prices and volumes are hedged in accordance with Empire's Risk Management Policy in an attempt to lessen the volatility in the Company's fuel expense and gain predictability.

3.2 Coal Price Forecast

The first five years of the coal price forecasts used for the Asbury, Riverton, Iatan, and Plum Point facilities were derived by Empire fuels personnel and reflect contract knowledge over those years. The values for subsequent years use escalators based on the U.S. Department of Energy's Energy Information Administration's (EIA) May 2010 projections.

Coal price projections for Asbury are shown in Table 3-2, those for Riverton are in Table 3-3, the coal price projections for Iatan 1 and 2 are shown in Table 3-4, and Plum Point's coal price projections are found in Table 3-5. Many utilities that consume coal have recently experienced cost increases due to increases in the cost of coal transportation.

NP

Table 3-2
Asbury Coal Price Forecast ($/MMBtu) ** Highly confidential in its entirety**

Table 3-3
Riverton Coal Price Forecast ($/MMBtu) ** Highly confidential in its entirety**

HC

NP

Table 3-4
Iatan Coal Price Forecast ($/MMBtu) ** Highly confidential in its entirety**

Table 3-5
Plum Point Coal Price Forecast ($/MMBtu) ** Highly confidential in its entirety**

HC

3.3 Natural Gas Price Forecast

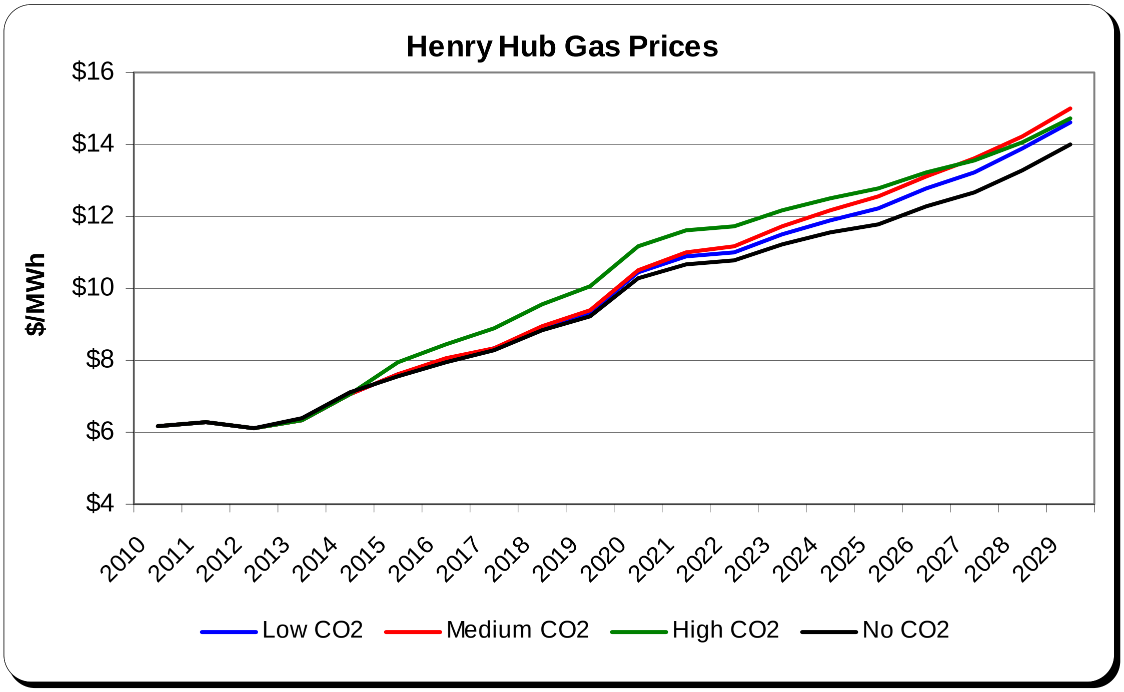
The natural gas price forecast used for this IRP is based on the Ventyx Fall 2009 Power Market Advisory Service Electricity & Fuel Price Outlook modified by Ventyx. Natural gas prices were developed for four carbon scenarios: no carbon, and low, base and high carbon tax assumptions. Any carbon tax would start no earlier than 2015. The natural gas prices are correlated to the CO_2 prices and are shown on Table 3-6 and Figure 3-1.

Table 3-6
Natural Gas Price Forecast ($/MMBtu)

Year	Base CO_2 Case	No CO_2 Case	Low CO_2 Case	High CO_2 Case
2010	6.16	6.16	6.16	6.16
2011	6.30	6.30	6.30	6.30
2012	6.12	6.13	6.12	6.12
2013	6.35	6.37	6.35	6.35
2014	7.07	7.11	7.07	7.07
2015	7.63	7.58	7.59	7.92
2016	8.03	7.95	7.98	8.47
2017	8.34	8.27	8.31	8.90
2018	8.94	8.84	8.90	9.58
2019	9.39	9.23	9.33	10.06
2020	10.49	10.29	10.45	11.19
2021	11.00	10.68	10.89	11.60
2022	11.17	10.78	11.00	11.70
2023	11.72	11.20	11.49	12.16
2024	12.17	11.55	11.90	12.51
2025	12.56	11.80	12.21	12.77
2026	13.13	12.28	12.77	13.22
2027	13.59	12.69	13.25	13.57
2028	14.23	13.29	13.89	14.06
2029	14.99	14.02	14.63	14.73

Source: Ventyx

Figure 3-1



Source: Ventyx

3.3.1 Natural Gas Price Forecasting Methodology

Ventyx produces natural gas price forecasts for each month at individual pricing hubs using its Natural Gas Sub-Module. The Operations Component for the sub-module consists of a model of the aggregate U.S. natural gas sector. For each month and iteration, it executes in the following manner:

- The Operations Component includes an econometric model of the continental U.S. demand in each of the sectors other than power, relating monthly consumption to the Henry Hub price.
- For each iteration of the Operations Module, natural gas demand by the power sector is taken from the prior iteration of the Power Module.
- Liquid natural gas (LNG) supply is forecast using a proprietary global LNG model and Henry Hub prices from the previous iteration. This model utilizes forecasts of global LNG demand and supply.
- Domestic supply is represented in the Operations Components by exogenous continental U.S. production declines and exogenous assumptions about deliveries from Alaska; a pair of econometric equations relating continental U.S. productive capacity additions to Henry Hub prices in previous months and continental U.S. capacity utilization to the current Henry Hub/West Texas Intermediate (WTI) price; and net storage withdrawals to balance supply and demand to the extent available storage capacity will permit.
- The Henry Hub price is simulated as the price that balances demand and supply, including net storage withdrawals.

3.3.2 Natural Gas Risk Management Policy

Empire originally enacted a Risk Management Policy (RMP) in 2001 that establishes the approach and internal policy that Empire will use to manage specifically its natural gas commodity risk. The policy is revised approximately each year to reflect increased knowledge and changes in markets and financial instruments. The RMP targets for hedging of natural gas are:

- A minimum of 10% of year four expected gas burn
- A minimum of 20% of year three expected gas burn
- A minimum of 40% of year two expected gas burn
- A minimum of 60% of year one expected gas burn[1]
- Up to 80% of any future year's expected requirement can be hedged if appropriate given the associated volume risk.

The RMP serves to minimize the exposure that Empire has to the impacts of fluctuating natural gas prices.

3.4 Fuel Oil Price Forecast

To forecast No. 2 Fuel Oil, Ventyx uses a technique similar to natural gas, where representative current New York Mercantile Exchange (NYMEX) pricing is blended to its internal forward view. Since crude oil is the raw material used to produce distillate oil, jet kerosene, and heavy fuel oil (e.g., various sulfur grades of #6 residual oil) as well as gasoline, Ventyx derives fuel oil forecasts for generators from its WTI Reference Case Forecast.

Ventyx produces its WTI Reference Case based on NYMEX future prices for WTI Oil and Fuel Oil #2, product price relationships between fuel oils and long-term supply and demand analysis of the WTI and global crude oil markets. The WTI forecast is based on 72 months of NYMEX Futures prices and on subsequent supply/demand fundamentals for the remainder for the forecast period. The WTI NYMEX prices are incorporated directly for the first 36 months and for the following 36 months by mean regression analysis with the supply/demand analysis.

A similar estimation technique as used to forecast monthly natural gas prices is used to project monthly oil prices.

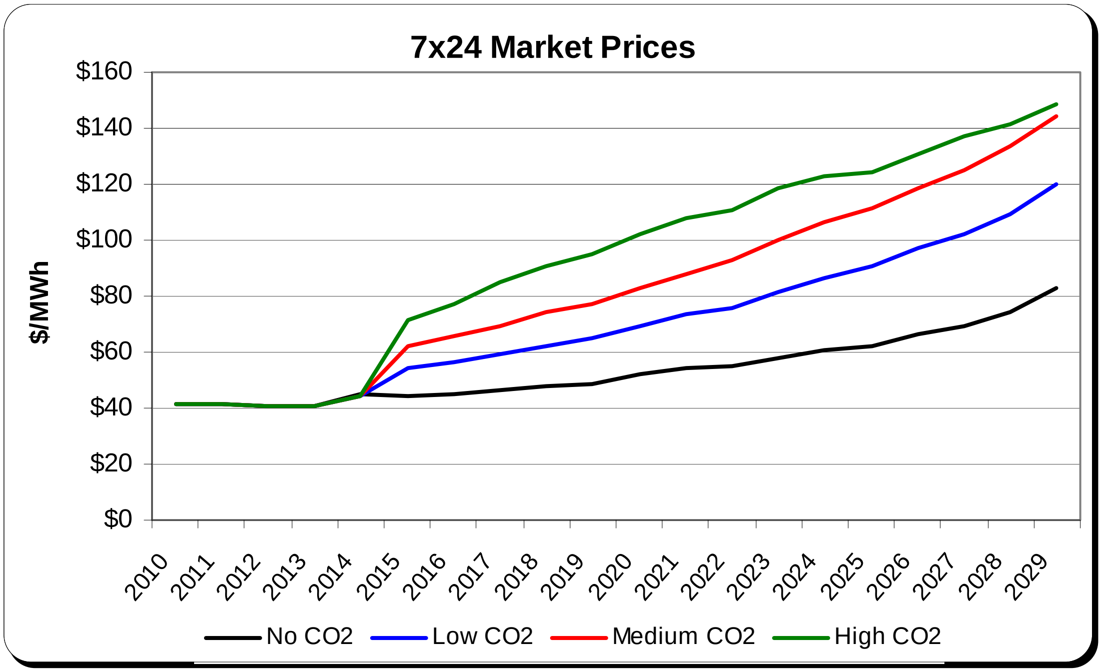
3.5 Market Price Forecast

Market prices for the Southwest Power Pool (SPP) were projected by Ventyx for use in the modeling. These prices reflect conditions in the market expected to be experienced by Empire and use the most recent market information available. Market prices were

[1] For example, as of July 2010, Year 1 is 2011, Year 2 is 2012, Year 3 is 2013 and Year 4 is 2014.

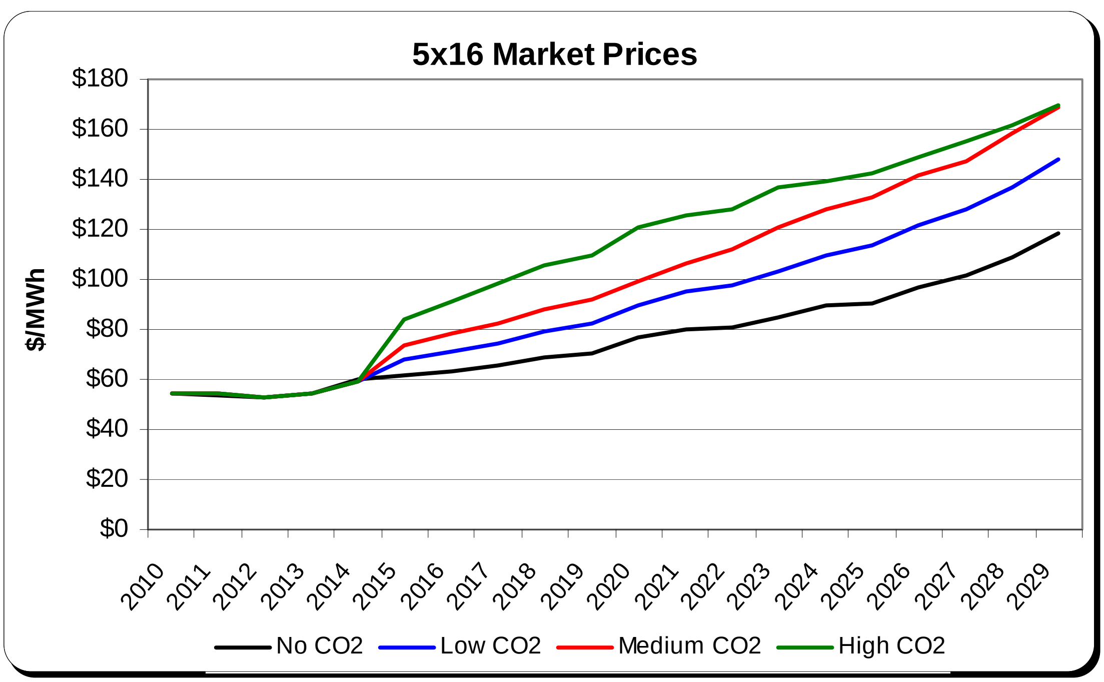
determined for each of the carbon tax scenarios. The projected on-peak market prices used for the modeling in this IRP are shown in Figures 3-2 and 3-3.

Figure 3-2
7 x 24 Market Prices – SPP



Source: Ventyx

Figure 3-3
5 x 16 Market Prices – SPP



Source: Ventyx

3.6 Capacity Margin

As a member of the SPP, Empire is required to maintain a minimum 12% capacity margin which is approximately equivalent to a 13.7% reserve margin. This value was used as the minimum reserve margin value for capacity planning in this IRP.

3.7 Financial Parameters

Empire's discount rate used for planning purposes is 7.78%. The Gross Domestic Product (GDP) Deflator used in all of the model runs is 2.5% per year throughout the forecast period. Levelized fixed charge rates were only applied in the screening portion of the modeling (in the Capacity Expansion Module). The values used are shown in Table 3-7.

Table 3-7
Levelized Fixed Charge Rates

Technology	Levelized Fixed Charge Rate (%)
Combustion turbine	11.59%
Combined cycle	11.17%
Coal/IGCC	10.59%
Distributed Generation	12.90%
Biomass	12.90%

Levelized fixed charge rates were not applied to capital costs for the units in the MIDAS modeling since the model was used to perform a full financial analysis including accelerated depreciation, annual rate base calculations, construction S-curves, and Allowance for Funds Used During Construction (AFUDC). All present value of revenue requirements (PVRR) calculations have been expressed in 2010 dollars.

No future resource is expected to have leased or rented facilities.

3.8 Emission Costs

Emission costs modeled in the IRP analysis included sulfur dioxide (SO_2), nitrogen oxides (NO_x), and Mercury (Hg). For the base case, carbon dioxide (CO_2) taxes began in 2015. Because the Clean Air Mercury Rule (CAMR) was vacated, the EPA is required to issue a new rule on how mercury is to be regulated by the end of 2011. Empire assumed a resumption of mercury emission costs and controls as of the beginning of 2015.

NO_x and SO_2, along with many other pollutants, are regulated by a number of state and federal statutes that complicates price projections for the costs of emissions, the limits on the emissions themselves, and the projected future levels of emissions. The emissions costs assumed in the analysis, reflecting a combination of state and federal requirements, are shown in Table 3-8.

Table 3-8
Emissions Costs – Base Environmental

Year	SO_2 ($/ton)	NO_x ($/ton)	Hg ($000/ton)	CO_2 ($/ton)
2015	153	1,006	40,000	21.48
2016	162	1,035	40,000	24.12
2017	170	1,063	40,000	27.04
2018	177	1,090	40,000	30.09
2019	182	1,106	40,000	32.21
2020	186	1,120	40,000	34.66
2021	188	1,131	40,000	37.22
2022	188	1,131	40,000	40.19
2023	188	1,131	40,000	43.23
2024	188	1,131	40,000	46.87
2025	188	1,131	40,000	50.18
2026	188	1,131	40,000	53.90
2027	188	1,131	40,000	58.00
2028	188	1,131	40,000	62.35
2029	188	1,131	40,000	67.18

Source: Ventyx (Hg estimate from Empire)

Four levels of CO_2 regulation were examined including a case in which no CO_2 regulation was enacted. Table 3-9 shows the projected CO_2 costs ($/ton) in a cap and trade system (referenced as a carbon tax in this IRP), assumed to be applicable no earlier than 2015. Because the optimization models are capable of expressly modeling allowance costs and impacts of carbon taxes, no separate environmental mitigation costs needed to be calculated for the supply-side resources enumerated in this Volume of the IRP report.

Table 3-9
Carbon Dioxide Tax Assumptions

	Low CO_2 Scenario	Base CO_2 Scenario	High CO_2 Scenario
2015	12.55	21.48	27.77
2016	13.58	24.12	30.38
2017	15.05	27.04	35.81
2018	16.35	30.09	40.37
2019	18.07	32.21	43.57
2020	19.43	34.66	48.23
2021	21.23	37.22	51.74
2022	22.98	40.19	55.65
2023	25.72	43.23	60.39
2024	28.51	46.87	65.29
2025	30.81	50.18	69.23
2026	33.84	53.90	73.84
2027	36.35	58.00	79.20
2028	38.60	62.35	85.03
2029	40.63	67.18	90.44

Source: Ventyx

For the low and high CO_2 scenarios, changes in SO_2, NO_x and mercury emission allowances prices and gas, oil, and coal prices were correlated with the CO_2 prices. Tables 3-10 through 3-14 show the correlated price projections for all four of the carbon tax scenarios. The coal prices shown are those that would be expected for any new coal-fired generation built in the future.

Table 3-10
Projected Coal Prices for Future Coal-Fired Resources – Carbon Scenarios ($/MMBtu)

	No CO_2 Scenario	Low CO_2 Scenario	Base CO_2 Scenario	High CO_2 Scenario
2017	2.34	2.30	2.13	1.95
2018	2.46	2.40	2.17	1.95
2019	2.57	2.49	2.22	1.95
2020	2.70	2.59	2.28	1.93
2021	2.84	2.70	2.33	1.93
2022	3.03	2.84	2.40	1.97
2023	3.22	2.95	2.46	2.09
2024	3.46	3.10	2.52	2.25
2025	3.70	3.25	2.58	2.42
2026	4.03	3.43	2.66	2.62
2027	4.19	3.47	2.72	2.72
2028	4.32	3.49	2.81	2.81
2029	4.45	3.51	2.89	2.89

Source: Ventyx

Table 3-11
Projected Oil Prices – Carbon Scenarios ($/MMBtu)

	No CO_2 Scenario	Low CO_2 Scenario	Base CO_2 Scenario	High CO_2 Scenario
2015	22.29	22.97	25.21	27.20
2016	23.31	24.23	27.20	29.34
2017	24.01	25.30	29.04	32.13
2018	24.66	26.32	30.93	34.52
2019	25.18	27.38	32.38	36.23
2020	25.51	28.16	33.71	37.89
2021	25.80	29.08	35.03	39.01
2022	25.92	29.83	36.22	39.66
2023	26.17	31.15	37.55	39.26
2024	26.34	32.43	38.81	39.51
2025	26.68	33.76	40.06	40.06
2026	27.23	35.67	41.49	41.49
2027	28.03	37.72	43.03	43.03
2028	29.88	41.13	44.82	44.82
2029	31.11	43.65	46.66	46.66

Source: Ventyx

Table 3-12
Projected SO_2 Allowance Prices ($/ton)

	No CO_2 Scenario	Low CO_2 Scenario	Base CO_2 Scenario	High CO_2 Scenario
2015	170	171	153	134
2016	189	189	162	138
2017	212	209	170	127
2018	240	233	177	111
2019	264	251	182	106
2020	296	275	186	118
2021	336	304	188	135
2022	400	350	188	160
2023	470	388	188	188
2024	470	362	188	188
2025	470	339	188	188
2026	470	305	188	188
2027	470	274	188	188
2028	470	244	188	188
2029	470	214	188	188

Source: Ventyx, Based on 2009 Fall Reference Case

Table 3-13
Projected Annual NO_x Allowance Prices ($/ton)

	No CO_2 Scenario	Low CO_2 Scenario	Base CO_2 Scenario	High CO_2 Scenario
2015	1,083	1,083	1,006	914
2016	1,155	1,149	1,035	925
2017	1,243	1,227	1,063	871
2018	1,352	1,321	1,090	821
2019	1,438	1,386	1,106	776
2020	1,548	1,472	1,120	681
2021	1,682	1,567	1,131	617
2022	1,850	1,686	1,131	541
2023	2,069	1,810	1,131	446
2024	2,414	2,009	1,131	483
2025	2,836	2,251	1,131	567
2026	3,483	2,573	1,131	697
2027	4,489	3,098	1,131	898
2028	5,072	3,251	1,131	1,014
2029	5,655	3,404	1,131	1,131

Source: Ventyx, Based on 2009 Fall Reference Case

Table 3-14
Projected Mercury Allowance Prices ($000/ton)

	No CO_2 Scenario	Low CO_2 Scenario	Base CO_2 Scenario	High CO_2 Scenario
2015	41,159	40,974	40,000	39,153
2016	41,521	41,246	40,000	39,140
2017	41,942	41,522	40,000	38,827
2018	42,391	41,828	40,000	38,724
2019	42,701	41,934	40,000	38,708
2020	43,051	42,108	40,000	38,712
2021	43,398	42,210	40,000	38,903
2022	43,767	42,325	40,000	39,230
2023	44,093	42,245	40,000	39,519
2024	44,397	42,125	40,000	37,294
2025	44,575	41,957	40,000	37,443
2026	44,645	41,593	40,000	37,502
2027	44,715	41,324	40,000	37,560
2028	44,785	41,111	40,000	37,619
2029	47,619	43,470	40,000	40,000

Source: Empire/Ventyx

4.0 New Conventional Resources

Future supply-side resources available to Empire over the twenty-year planning horizon include both conventional and renewable resources. The conventional resources considered in the IRP are described in this Section of the report. The renewable resources considered in the IRP are described in Section 5.0.

A variety of conventional resources were examined in the course of preparing this IRP. These resources included supercritical coal, CT, CC, nuclear (PPA only), distributed generation, integrated gasification combined cycle (IGCC), and the conversion of Riverton 12 from a CT to CC. The capital costs modeled for each resource option include only generic costs for new transmission required; not those costs expected at any specific location due to the current methods that the SPP uses to plan and cost out new transmission projects. Costs are included for the switching station at the power plant. O&M cost estimates are provided. Empire believes the uncertainty that surrounds the O&M costs for any future power plant is significantly overshadowed by the uncertainty related to any of natural gas prices, market prices, and the level of carbon taxes. Thus, the uncertainty associated with O&M costs is not considered further in this IRP.

4.1 Supercritical Coal

In a supercritical coal unit, chunks of coal are crushed into fine powder in the pulverizers and are fed into a combustion unit (boiler or furnace) where it is burned. Heat from the burning coal is used to generate steam that is used to spin one or more turbines to generate electricity. Coal units currently generate about half of the electricity produced annually in the U.S.

As modeled, the coal option available to Empire represents its ownership share of a larger unit. As larger units benefit from economies of scale, this modeling choice was made to ensure Empire was able to take advantage of the cost effectiveness represented by the larger units. However, the actual timing and ownership share of units that Empire might be able to participate in will be dependent on plans of other utilities in the region and are expected to be largely out of Empire’s control. The data used in the modeling are shown in Table 4-1.

Cost and emission data are based on information from a supercritical coal unit currently under construction in the region. Supercritical coal units with carbon capture and sequestration are not assumed to be commercially viable within the planning horizon modeled in this IRP. Costs were developed for a coal unit equipped with CCS prior to making a judgment on the earliest feasible year of installation. The data are presented to show the estimated cost and efficiency differences between a traditional coal-fired unit and one equipped with CCS.

Table 4-1
Supercritical Coal Performance Parameters

Parameter	No CCS	With CCS	PPA – No CCS
Earliest feasible year of installation	2020	Outside of planning horizon	2017
Size, MW (net)	50*	50*	50*
Full load heat rate, Btu/kWh	9,220	11,986	9,220
Lead time, months	60	60	
Capital cost, $/kW (2010 $)	2,400	4,591	-
Fixed O&M, $/kW-year	27.53	32.15	363.29
Variable O&M, $/MWh	4.59	6.15	4.59
Equivalent Forced Outage Rate, %	6.0	7.0	6.0
Maintenance Outage Rate, %	6.5	7.5	6.5
SO_2 Emissions, lbs/MMBtu	0.03	0.03	0.03
NO_x Emissions, lbs/MMBtu	0.05	0.05	0.05
CO_2 Emissions, lbs/MMBtu	210	21	210
Mercury Emissions, lbs/MMBtu	0.001	0.001	0.001
*Ownership share of a larger unit.			

With the assumption that carbon dioxide (CO_2) may eventually be regulated (either cap and trade or a tax) with an associated requirement to significantly reduce CO_2 emissions in the future, CCS may need to be proven as a viable technology in order for coal-fired generation to continue to be a future new resource option. As part of its efforts to examine CCS, Empire is one of the five electric utilities participating in the Missouri Carbon Sequestration Project (MCSP). This project is researching the feasibility of shallow carbon sequestration within geologic formations in Missouri.

Phase I of the MCSP has been completed and funds to move the project into its second phase were announced in April 2010. Carbon capture is currently under development. Because carbon sequestration is the other component necessary for successful CCS, the Missouri utilities are supporting research efforts to determine feasibility.

Other utility participants include AmerenUE, Associated Electric Cooperative, City Utilities of Springfield, and KCP&L. Research members of the project include City Utilities of Springfield, Missouri Department of Natural Resources, Missouri State University, and Missouri University of Science & Technology. Supporting Organizations include Missouri Energy Development Association, Missouri Public Service Commission, Missouri Public Utility Alliance, and the EPA Region VII.

4.2 Combustion Turbine

Combustion turbines typically burn natural gas and/or No. 2 fuel oil and are available in a wide variety of sizes and configurations. CTs are generally used for peaking and reserve purposes because of their relatively low capital costs, higher full load heat rate, and the higher cost of fuel when compared to conventional coal-fired baseload capacity. CTs, particularly aeroderivatives, have the added benefit of providing quick-start capability in certain configurations. In this IRP, both simple cycle and aeroderivative CTs were options in the optimization modeling with data used as shown on Table 4-2. Data for capital costs for the CTs are based on manufacturers' information provided by Siemens, General Electric, and Pratt and Whitney.

Table 4-2
Combustion Turbine Performance Parameters

Parameter	Aeroderivative CT	Simple Cycle CT
Earliest feasible year of installation	2015	2015
Size, MW (net)	60	115
Full load heat rate, Btu/kWh	11,000	10,500
Lead time, months	48	48
Capital cost, $/kW (2010 $)	674	573
Fixed O&M, $/kW-year	10.85	13.23
Variable O&M, $/MWh	3.00	3.00
Equivalent Forced Outage Rate, %	3.6	3.6
Maintenance Outage Rate, %	4.1	4.1
NO_x Emissions, lbs/MMBtu	0.03	0.03
CO_2 Emissions, lbs/MMBtu	120	120

4.3 Combined Cycle

In a combined cycle (CC) facility, the hot exhaust gases from one or more CTs pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. Combustion turbine combined cycle systems typically burn natural gas and are available in a wide variety of sizes and configurations. In Empire's IRP, two CC options were available for selection: 1) a new unsited CC facility, and 2) the conversion of the Riverton 12 CT to a CC unit. Riverton 12 can be converted into a CC unit through the addition of an HRSG and a steam turbine which would result in 100 MW of additional capacity. The Riverton12 conversion costs are based on an estimate prepared by Sega, Inc., an engineering and technical services company based in Overland Park, Kansas. The general CC unit capital costs are based on a cost estimate from a CT manufacturer plus the conversion cost estimates from Sega. CC with CCS is assumed to not be commercially viable during the planning horizon modeled for this IRP. The data used for modeling are shown on Table 4-3.

Table 4-3
Combined Cycle Performance Parameters

Parameter	General CC	CC with CCS	Riverton 12 Conversion
Earliest feasible year of installation	2015	Outside of planning horizon	2015
Size, MW (net)	250	250	100*
Full load heat rate, Btu/kWh	7,500	9,750	7,500
Lead time, months	48	48	48
Capital cost, $/kW (2010 $)	720	1,584	1,253
Fixed O&M, $/kW-year	12.48	22.10	12.48
Variable O&M, $/MWh	2.07	3.15	2.07
Equivalent Forced Outage Rate, %	5.50	5.50	5.50
Maintenance Outage Rate, %	7	6	7
NO_x Emissions, lbs/MMBtu	.01	.01	.01
CO_2 Emissions, lbs/MMBtu	120	12	120

*Represents the incremental capacity of the CC unit only, not the total including the CT.
1. Same fixed costs as currently projected for Riverton 12 as a CT. Thus, no additional fixed costs.

4.4 Nuclear

New nuclear units are currently being pursued around the country at brownfield sites – meaning additional units are being planned at sites with operating units. New nuclear unit designs have been submitted to the U.S. Nuclear Regulatory Commission (NRC) and have received or are awaiting design approval. Small Modular Reactors (SMR) are receiving much attention and interest as well. These are new reactor designs for which each module is much smaller than the typical approximately 1,000 MW associated with the nuclear units designed and built in the 1970s and 1980s.

Although Empire is not aware of any opportunities for it to become a joint owner of a nuclear unit in the region, for purposes of the IRP, Empire considered a nuclear unit PPA as an option starting in 2025. At some point in the future, possibly within the planning horizon and possibly later than the end of the planning horizon, it is conceivable that, within the region, one or more new nuclear units could be pursued as an additional unit at an existing nuclear power plant site.

The IRP modeling assumes that Empire would participate in a PPA with the owner of a new nuclear unit. However, the actual timing and size of such a PPA will be dependent on plans of other utilities in the region and are expected to be largely out of Empire's control.

Table 4-4
Nuclear PPA Performance Parameters

Parameter	Value
Earliest feasible year of installation	2025
Size, MW (net)	50*
Full load heat rate, Btu/kWh	10,300
PPA cost, $/kW-year	1035.74
Variable O&M, $/MWh	0.49
Equivalent Forced Outage Rate, %	3.8
Maintenance Outage Rate, %	6.2
Emissions	None
*Represents share of a larger jointly-owned unit.	

4.5 Distributed Generation

Distributed generation (DG) refers to small-scale power plants that differ from traditional electricity supply due to their small size, location, and grid connection. DGs are located at or near the point at which the power is used. Such installations relieve congestion in power lines during periods of peak demand, helping to defer investments in additional transmission and distribution capacity. DG facilities are often installed on the distribution system as opposed to on the transmission system, where generation is typically connected. DG facilities may also be used to boost the quality and reliability of local electricity service by providing voltage control and backup power to customers who require such "premium" service. Data used to model distributed generation are shown in Table 4-5.

Table 4-5
Distributed Generation Performance Parameters

Parameter	Value
Earliest feasible year of installation	2014
Size, MW (net)	5
Full load heat rate, Btu/kWh	10,000
Lead time, months	12
Capital cost, $/kW (2010 $)	1,404
Fixed O&M, $/kW-year	16.03
Variable O&M, $/MWh	7.12
Equivalent Forced Outage Rate, %	0
Maintenance Outage Rate, %	0

4.6 Integrated Gasification Combined Cycle (IGCC)

Coal gasification is a process that converts solid coal into a synthetic gas composed mainly of carbon monoxide and hydrogen. Integrated gasification combined cycle (IGCC) combines both steam and gas turbines ("combined cycle"). The fuel gas leaving the gasifier must be cleaned (to very high levels of removal efficiencies) of sulfur compounds and particulates in order to be a suitable fuel for combustion. After the fuel gas has been cleaned, it is burned and expands in a gas turbine. Steam is generated and superheated in both the gasifier and the heat recovery unit downstream from the gas turbine. The flue gas is then directed through a steam turbine to produce electricity. IGCC plants can achieve up to 45 percent efficiency depending on the level of integration of the various processes, greater than 99 percent SO_2 removal, and NO_x below 50 parts per million.[2] The analysis assumes that Empire would participate in a share of a larger jointly-owned unit. Data used to model IGCC are shown in Table 4-7.

Table 4-6
IGCC Performance Parameters

Parameter	Value
Earliest feasible year of installation	2020
Size, MW (net)	50*
Full load heat rate, Btu/kWh	9,300
Lead time, months	
Capital cost, $/kW (2010 $)	2437
Fixed O&M, $/kW-year	38.67
Variable O&M, $/MWh	2.92
Equivalent Forced Outage Rate, %	6.0
Maintenance Outage Rate, %	6.5
SO_2 Emissions, lbs/MMBtu	.02
NO_x Emissions, lbs/MMBtu	.01
CO_2 Emissions, lbs/MMBtu	210
Mercury Emissions, lbs/MMBtu	.0005
*Represents a share of a larger jointly-owned unit.	

IGCC with CCS is assumed to not be commercially viable during the planning horizon modeled for this IRP.

[2] Source: "Clean Coal Technologies for Developing Countries," World Bank Technical Paper No. 286, Energy Series, E. Stratos Tavoulareas and Jean-Pierre Charpentier, July 1995. http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/igccsubs.stm, accessed May 2006.

5.0 New Renewable Resources

The regulatory requirements for renewable resources in certain of Empire's jurisdictions are discussed first in the section on Renewable Portfolio Standards. The second section contains a discussion of the renewable resources considered in this IRP.

5.1 Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) or Renewable Energy Standards have been established by the voters or the legislature in Missouri, Kansas, and Oklahoma. The requirements for each are provided below.

5.1.1 RPS – Missouri

The RPS (Proposition C) approved by the voters during the November 4, 2008 election, and currently undergoing rulemaking at the MPSC, mandates percentages of an electric utility's sales that are to be provided by renewable energy resources by the dates shown in Table 5-1. The RPS further requires that a specific percentage be provided by solar energy unless a utility is exempted. Renewable energy resources as approved by the voters and as defined in the proposed rules in Docket EX-2010-0169 (July 1, 2010, as posted in the August 16, 2010 *Missouri Register*) are:

- Wind
- Solar, including solar thermal sources utilized to generate electricity, photovoltaic cells, or photovoltaic panels
- Dedicated crops grown for energy production
- Cellulosic agricultural residues
- Plant residues
- Methane from landfills or wastewater treatment
- Clean and untreated wood, such as pallets
- Hydropower (not including pumped storage) that does not require a new diversion or impoundment of water and that has generator nameplate ratings of ten (10) MW or less
- Fuel cells using hydrogen produced by any of the renewable energy resources shown in the list above
- Other sources of energy not including nuclear that become available after November 4, 2008, and are certified as renewable by the department [Missouri Department of Natural Resources].

A multiplier of 1.25 will apply to all in-state resources (meaning that each 1 kWh of renewable energy generated within Missouri will count as 1.25 kWh for purposes of determining compliance with the Missouri RPS).

Table 5-1
Missouri Renewable Portfolio Standard

Dates	RES Percentage (no less than)
2011-2013	2
2014-2017	5
2018-2020	10
Beginning in 2021	15
Notes: 1. Percentage of an electric utility's sales. 2. Some or all of the requirement may be satisfied by the purchase of Renewable Energy Credits (REC). 3. Each kWh of eligible energy generated within Missouri will count as 1.25 kWh.	

As of January 20, 2009, Empire had renewable energy resource aggregate nameplate capacity equal to or greater than 15% of its fossil-fired generating capacity.

Table 5-2
Empire Renewable Resources

Name of Resource	Type of Resource	Nameplate (MW)
Ozark Beach	Hydroelectric	4 units – 16 MW total
Elk River	Wind	150*
Meridian Way	Wind	105*
TOTAL RENEWABLE		271
Total 2010 Fossil-Fired Capacity		1241
% of Total represented by Renewables		**21.8%**
*Represents the nameplate capacity for these facilities. Actual rated capacity is 7 MW and 8 MW, respectively.		

5.1.2 RPS – Kansas

The state legislature passed HB 2369 in 2009 establishing an RPS in Kansas. The rulemaking process at the Kansas Corporation Commission related to the RPS is ongoing. Utilities are required to generate or purchase a certain amount of their electricity peak demand for Kansas-only customersfrom eligible renewable resources as shown in Table 5-3.

Table 5-3
Kansas Renewable Portfolio Standard

Years	Percentage of Utility Peak Capacity Demand
2011-2015	10%
2016-2019	15%
2020 and onward	20%
Note: % calculated based on the average demand of the prior three years	

Renewable energy resources are defined by the statute to include:

- Wind
- Solar thermal sources
- Photovoltaic cells and panels
- Dedicated crops grown for energy production
- Cellulosic agricultural residues
- Plant residues
- Methane from landfills or from wastewater treatment
- Clean and untreated wood products such as pallets
- Existing hydropower
- New hydropower, not including pumped storage, that has a nameplate rating of 10 MW or less
- Fuel cells using hydrogen produced by one of the above-named renewable energy resources
- Other sources of energy, not including nuclear power, that become available after the legislation becomes effective, and that are certified as renewable by rules and regulations of the Kansas Corporation Commission.

Renewable resources installed in Kansas qualify for a 1.1 multiplier for the purpose of compliance. The RPS will apply to all power sold to Kansas retail customers whether the power they consume is generated or purchased inside or outside of the state.

5.1.3 RPS – Oklahoma

In May 2010, Oklahoma enacted HB 3028 that established a renewable energy goal for electric utilities operating in the state. The goal is "that 15% of all installed capacity of electricity generation within the state by the year 2015 be generated from renewable energy sources." Qualifying renewable energy resources include:

- Wind
- Solar
- Photovoltaic
- Hydropower
- Hydrogen
- Geothermal
- Biomass, including agricultural crops, wastes, and residues, wood, animal and other degradable organic wastes, municipal solid waste, and landfill gas
- Distributed generation from an eligible renewable energy resource less than 5 MW
- Other renewable energy resources approved by the Commission
- Demand-side management and energy efficiency.

The percentage of renewable energy shall be determined by dividing all installed capacity of renewable electricity generation in Oklahoma by the total installed capacity of all electricity generation in Oklahoma.

Empire has no electric generating resources in Oklahoma.

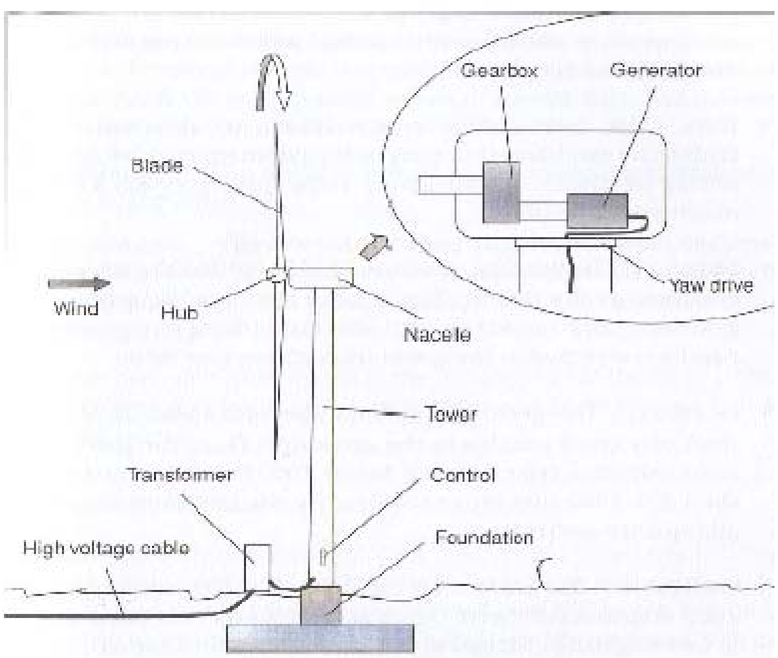
5.2 Renewable Resources

Empire examined a range of renewable resources in this IRP. These include wind, biomass (chicken/turkey waste, landfill gas and others), and solar (PV and solar thermal). Empire currently burns fuel derived from tires at its Asbury station. Empire purchases wind energy from Elk River Windfarm, LLC, whose wind generation facility (Elk River Windfarm) is near Beaumont, Kansas. Empire also purchases wind energy from Cloud County Wind Farm, LLC (the Meridian Way Wind Farm) in Cloud County, Kansas.

5.2.1 Wind

Wind energy systems for utility applications transform the kinetic energy of the wind into electrical energy. Horizontal-axis turbines (propeller-style machines) are the most common wind turbine configuration today, constituting almost all of the utility-scale (greater than 100 kW) applications. Figure 5-1 shows this typical wind turbine configuration.

Figure 5-1
Wind Turbine Configuration



Turbine subsystems include:

- A rotor, or blades, that convert the wind's energy into rotational shaft energy

- A nacelle (enclosure) containing a drive train, usually including a gearbox (not all turbines require a gearbox) and a generator
- A tower to support the rotor and drive train
- Electronic equipment such as controls, electrical cables, ground support equipment, and interconnection equipment.[3]

The American Wind Energy Association (AWEA) reported as of mid-2010 that the U.S. had 36,303 MW of installed wind energy capacity. The top fifteen states as reported by AWEA as of mid-2010 are shown in Table 5-4.

Table 5-4
Installed Wind Energy Capacity in the U.S. (July 2010)

State	Installed Capacity (MW)	Rank
Texas	9,707	1
Iowa	3,670	2
California	2,739	3
Oregon	1,920	4
Washington	1,914	5
Illinois	1,848	6
Minnesota	1,797	7
New York	1,274	8
Colorado	1,248	9
North Dakota	1,222	10
Oklahoma	1,130	11
Indiana	1,127	12
Wyoming	1,101	13
Kansas	1,026	14
Pennsylvania	748	15

5.2.1.1 Wind – Missouri

The profile of wind resources shown on Figure 5-2 reveals that Class 3 or lower wind resources exist in Empire's Missouri service territory. Generally wind resources need to be at least Class 3 (the highest wind ranking is Class 7) in order to be considered suitable for wind energy development. This map shows some suitable resources in the Ozark Plateau. Wind resource maps from other sources have indicated that the northwest corner of the State has the highest class wind rankings.[4] The resources that AWEA reports to be on-line in Missouri are shown in Table 5-5.

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[3] Figure, general information and state project information from web site of the American Wind Energy Association www.awea.org.
[4] Figure 3-44, "Missouri annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-44m.html.

Figure 5-2(a)
Wind Resources in Missouri

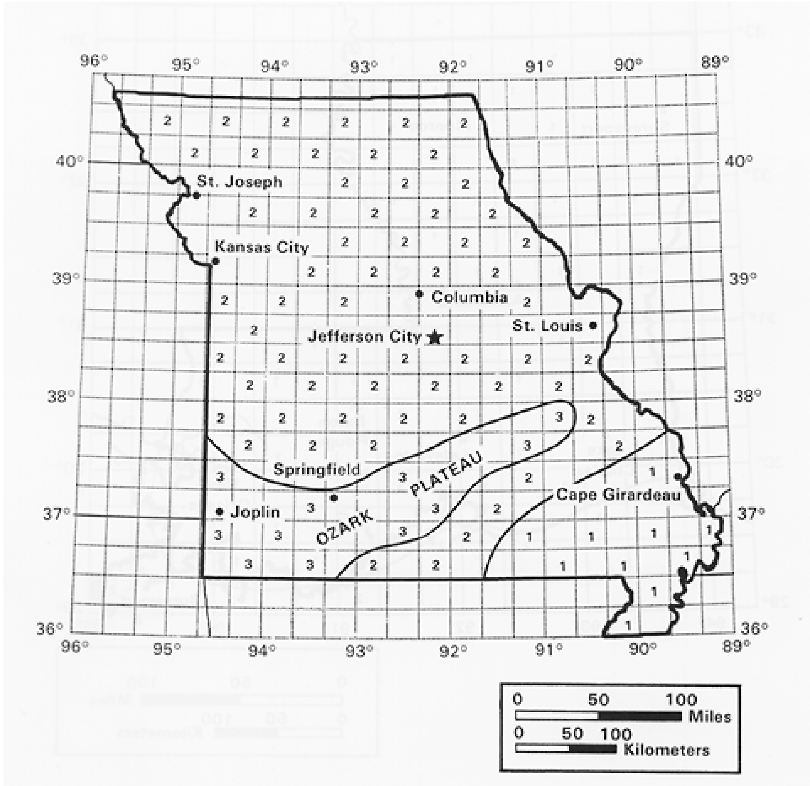


Figure 5-2(b)
Wind Resources in Missouri

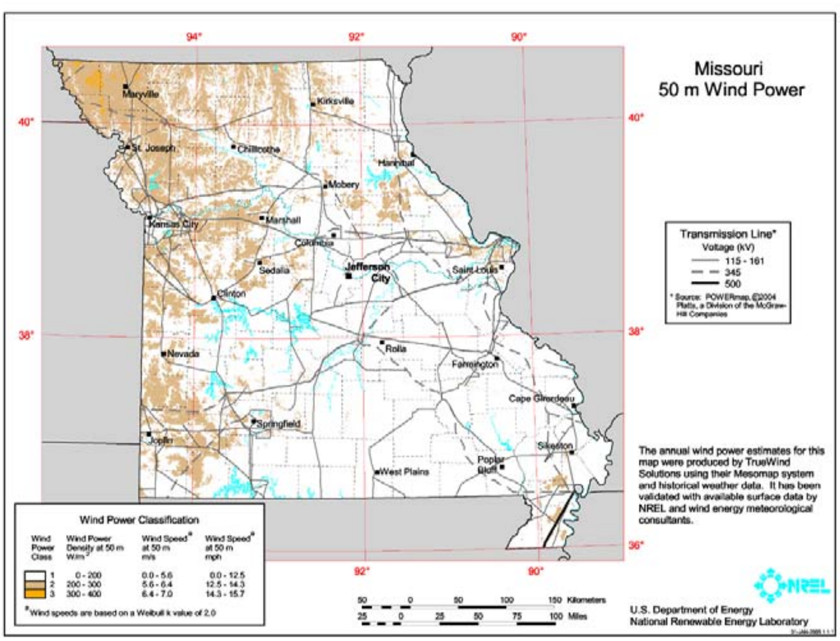


Table 5-5
Wind Energy Projects in Missouri

Year of Operation	Size (MW)	Name	Developer	Utility Purchaser
2007	56.7	Bluegrass Ridge Wind energy project	Wind Capital Group/John Deere Capital	Associated Electric Cooperative (AECI)
2008	5	Loess Hills Wind Energy Center	Wind Capital Group/John Deere Capital	Missouri Joint Municipal Electric Utility Commission
2008	50.4	Cow Branch Wind Energy Center	Wind Capital Group/John Deere Capital	AECI
2008	50.4	Conception Wind Project	Wind Capital Group/John Deere Capital	AECI
2009	146	Farmers City	Iberdrola Renewables	
2010	148.5	Lost Creek Ridge Wind Farm	Wind Capital Group	AECI

5.2.1.2 Wind – Kansas

The American Wind Energy Association ranks Kansas third in the nation (behind North Dakota and Texas) in potential wind energy production. The resource map in Figure 5-3(a) and (b) shows the Class 3 and 4 wind resources in Kansas.[5] The resources that AWEA reports to be on-line in Kansas are shown in Table 5-6.

[5] Figure 3-42, "Kansas annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-42m.html.

Figure 5-3(a)
Kansas Wind Resource Map

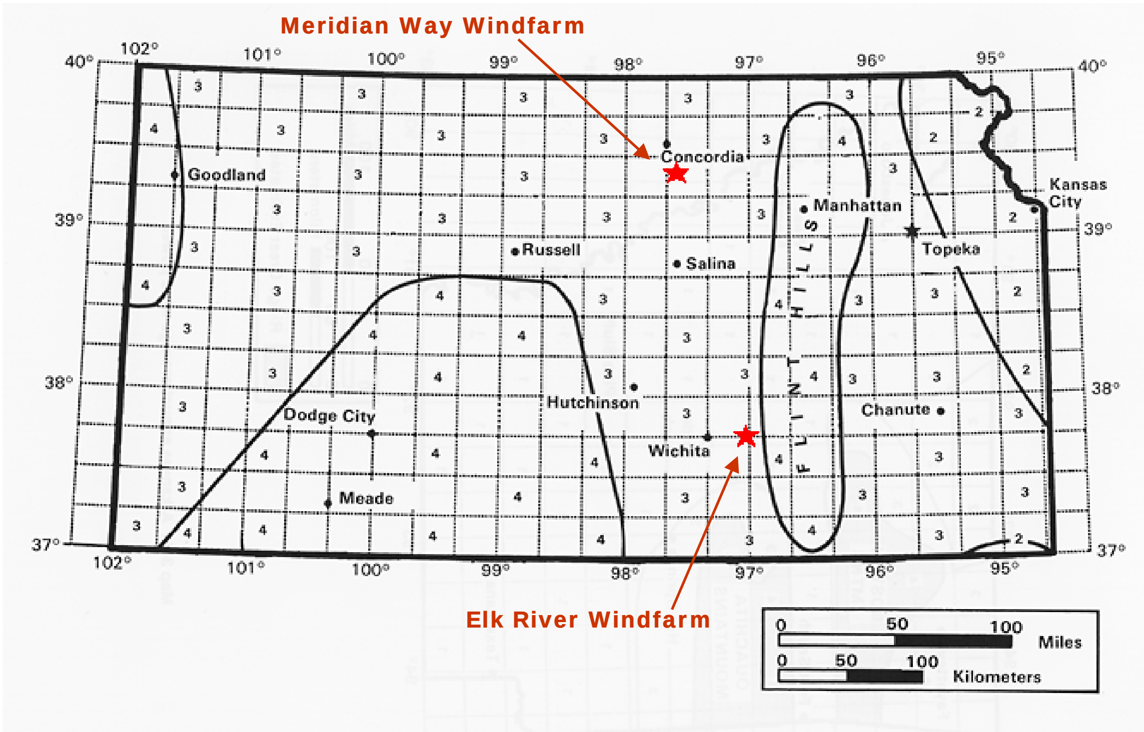


Figure 5-3(b)
Kansas Wind Resource Map

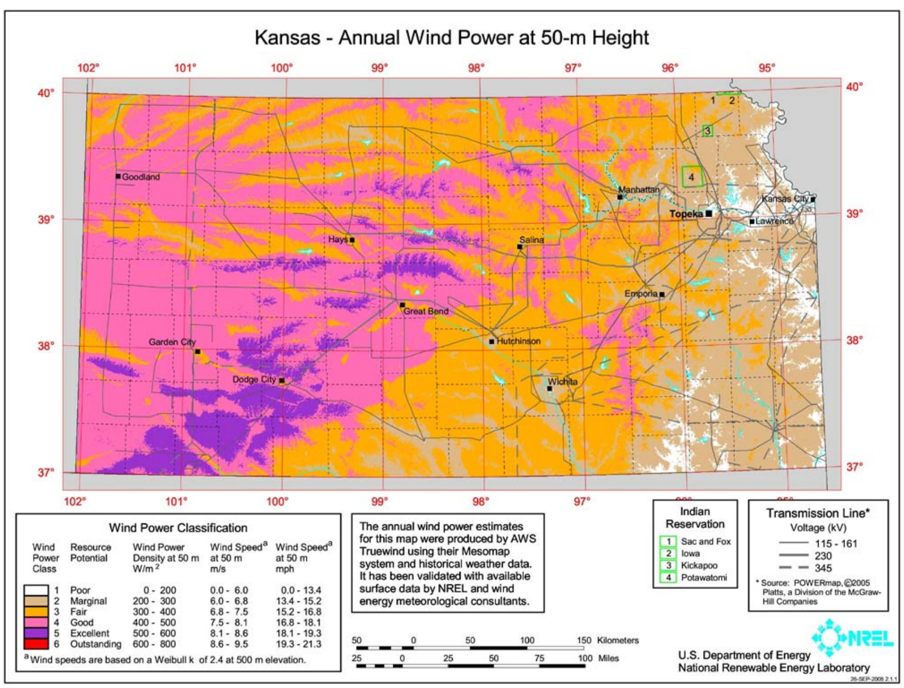


Table 5-6
Wind Energy Projects in Kansas

Year of Operation	Size (MW)	Name	Developer	Utility Purchaser
1999	1.5	St. Mary's	Western Resources	Western Resources
2001	112.2	Gray County Wind Farm	FPL Energy	Aquila
2005	150	Elk River Wind Farm	PPM Energy[1]	Empire
2006	100.5	Spearville Wind Energy Facility	Kansas City Power & Light	Kansas City Power & Light
2008	100.8	Smoky Hills Wind Farm	Tradewind Energy	Sunflower Electric/Midwest Energy/BPU
2008	148.5	Smoky Hills II	Tradewind Energy	
2008	96	Meridian Way	Horizon Wind Energy	Westar
2008	105	Meridian Way II	Horizon Wind Energy	Empire
2009	100	Flat Ridge Wind Farm	BP Alternative Energy/Westar	Westar
2009	99	Central Plains	Westar	Westar
2010	12.5	Greensburg	John Deere Wind	
1. Elk River Wind Farm is now owned by Iberdrola Renewables.				

5.2.1.3 Wind – Oklahoma

Oklahoma ranks eighth nationwide in potential wind energy production with most Class 3 and higher wind resources located in the western portion of the state. The resource map in Figure 5-4(a) and (b) shows the Class 3 and 4 wind resources in Oklahoma.[6] The resources that AWEA reports to be on-line and under construction in Oklahoma are shown in Table 5-7.

[6] Figure 3-45, "Oklahoma annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-45m.html.

Figure 5-4(a)
Oklahoma Wind Resource Map

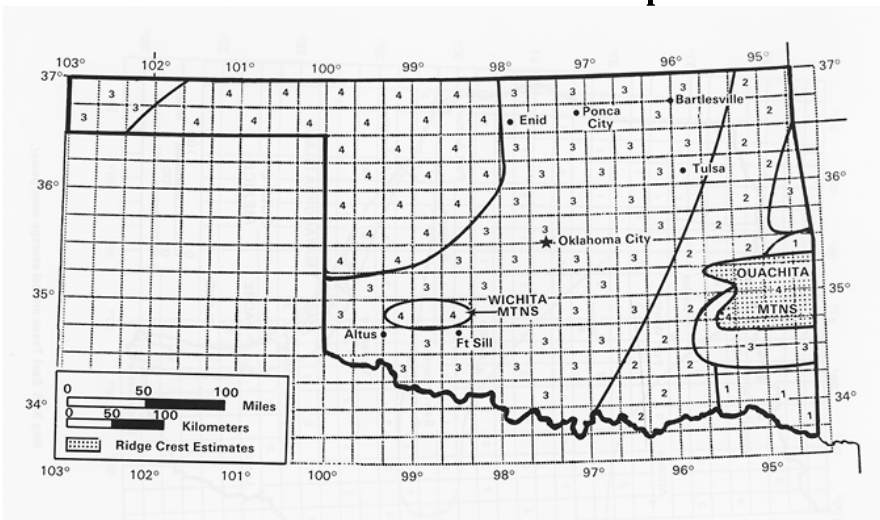


Figure 5-4(b)
Oklahoma Wind Resource Map

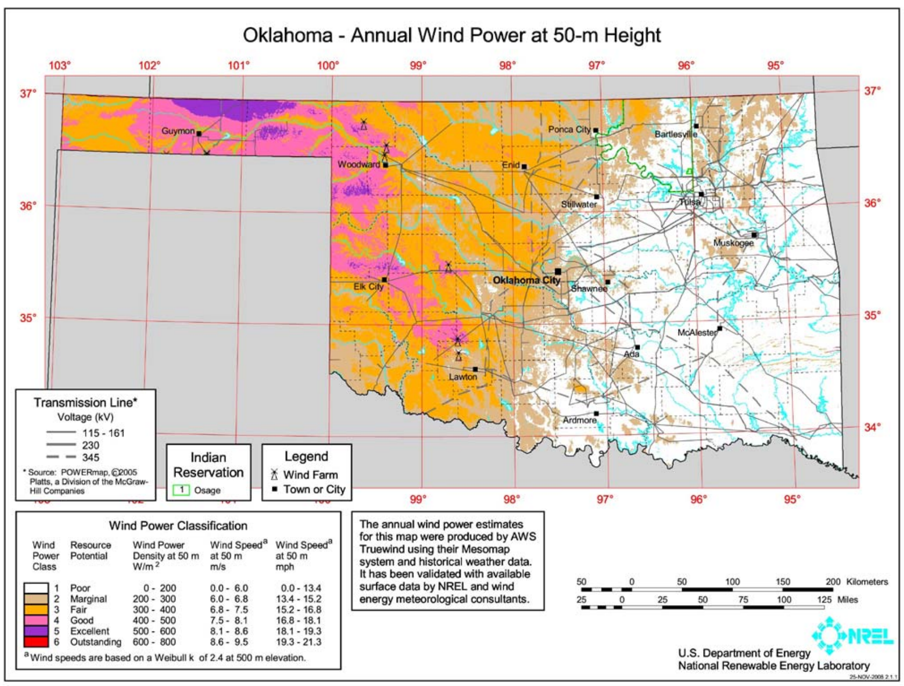


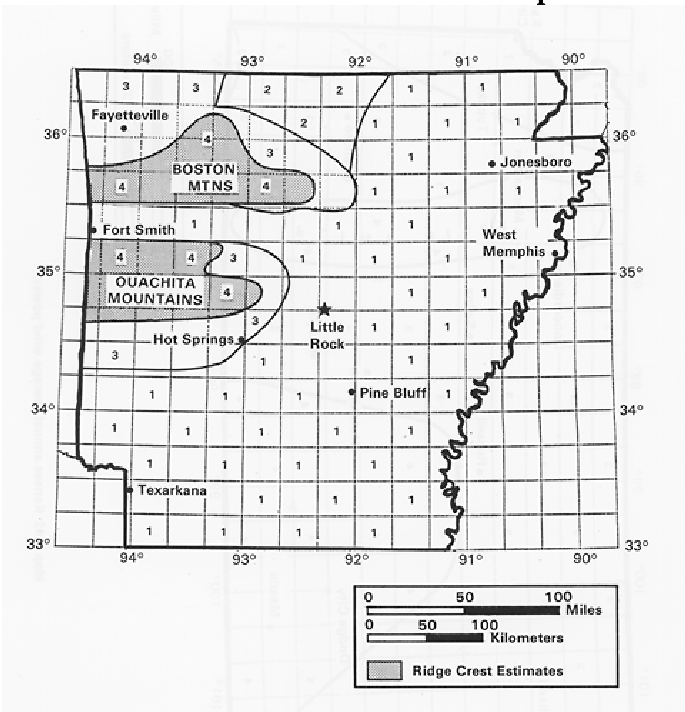
Table 5-7
Wind Energy Projects in Oklahoma

Year of Operation	Size (MW)	Name	Developer	Utility Purchaser
Operational				
2003	102	Oklahoma Wind Power Center	FPL Energy	Oklahoma Municipal Power Authority; Oklahoma Gas & Electric
2003	74.25	Blue Canyon Wind Power	Consortium	Western Farmers Electric Coop
2005	147	Weatherford Wind Energy Center	FPL Energy	Public Service Company of Oklahoma (AEP)
2005	0.05	Bergey Windpower Headquarters	Bergey Windpower	Bergey Windpower Headquarters
2005	151.2	Blue Canyon II	Horizon Wind Energy	Public Service Company of Oklahoma (AEP)
2006	60	Centennial Wind Energy Project	Invenergy	Oklahoma Gas & Electric (OG&E)
2007	94.5	Sleeping Bear	Chermac Energy Corp/Edison Mission Group	Public Service Company of Oklahoma (AEP)
2007	60	Centennial Wind Energy Project	Chermac Energy/Invenergy	OG&E
2008	123	Red Hills	Acciona	
2008	18.9	Buffalo Bear	Edison Mission Group	Western Farms Electric Coop
2009	34.5 + 64.5	Blue Canyon V	Horizon-EDPR	Public Service Company of Oklahoma (AEP)
2009	98.9	Elk City	NextEra Energy Resources	
2009	101.2	OU Spirit	CPV/OG&E	OG&E
Under Construction				
	151.8	Keenan II	CPV Renewable Energy	OG&E
	99.2	Minco Wind	NextEra Energy Resources	
	129.6	Taloga	Edison Mission Group	OG&E

5.2.1.4 Wind – Arkansas

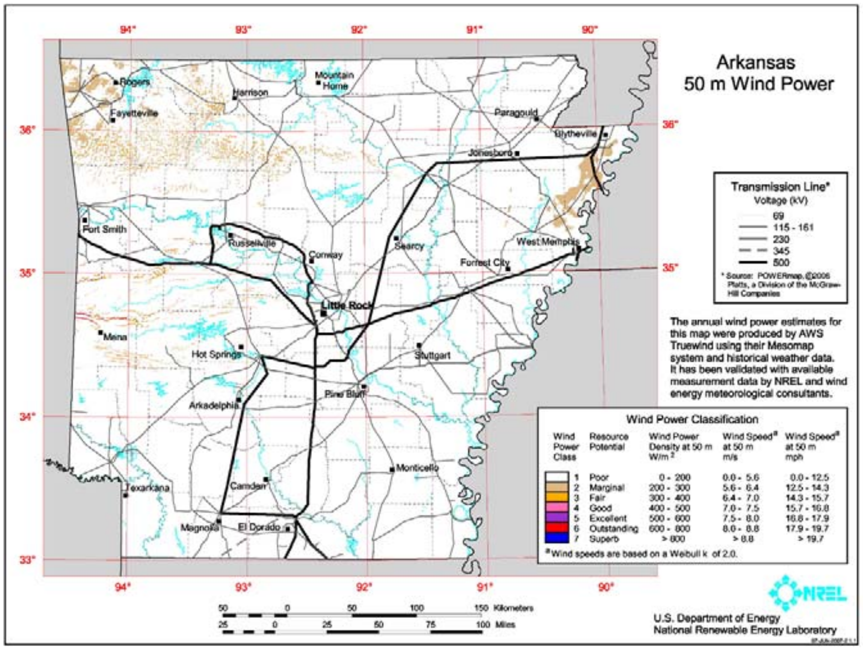
The resource map in Figure 5-5(a) and (b) shows the Class 3 and 4 wind resources in Arkansas.[7] Only one very small wind resource is reported to be operational by AWEA, 0.1 MW at the Bitworks Prairie Grove Industrial Park. AWEA reports no proposed projects.

Figure 5-5(a)
Arkansas Wind Resource Map



[7] Figure 3-41, "Arkansas annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-41m.html.

Figure 5-5(a)
Arkansas Wind Resource Map



The SPP has certified the capacity that Empire counts for both Elk River (7 MW) and Meridian Way (8 MW). For purposes of planning in the IRP, 5% of the nameplate of any new wind resource counts toward the capacity margin calculation.

Wind performance parameters are shown in Table 5-8.

Table 5-8
Wind Performance Parameters

Parameter	PPA
Earliest feasible year of installation	2017
Size, MW (net)	100
Energy Cost, $/MWh (2010 $)*	59
Fixed O&M, $/kW-year	-
Variable O&M, $/MWh (wind regulation only)	5.13
Equivalent Forced Outage Rate, %	-
Capacity Factor, %	43
*Production tax credit assumed to expire in 2012 which results in an adjustment to the energy cost.	

5.2.2 Biomass

Biomass electric generation is currently the largest source of renewable energy that is not hydroelectric in the U.S. Biomass means any plant-derived organic matter available on a renewable basis including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, municipal wastes and other waste materials. Waste energy consumption generally falls into categories that include municipal solid waste, landfill gas, and other. Other biomass includes agriculture byproducts/crops, sludge waste, tires, and other biomass solids, liquids, and gases. Biofuels being developed from biomass resources include ethanol, methanol, biodiesel, Fischer-Tropsch diesel, and gaseous fuels such as hydrogen and methane. [8]

Biomass resources available in Missouri, as reported by the National Renewable Energy Laboratory, are shown on Figure 5-6. For the sixteen counties[9] that comprise the Empire service territory, the biomass resource potential is quite small.

5.2.2.1 Biomass – Chicken/Turkey Waste

Chicken and/or turkey wastes represent a form of biomass that is prevalent in Empire's service territory. Research on studies conducted for facilities in states outside of Missouri concluded that the cost of power from such a facility would be about 8 cents/kWh and that the heat content of the fuel (chicken or turkey waste mixed with a wood waste product) would be 5,000 to 7,000 Btu/lb.[10]

5.2.2.2 Biomass – Landfill Gas

The U.S. Energy Information Administration describes landfill gas as follows[11]:

Municipal solid waste contains significant portions of organic materials that produce a variety of gaseous products when dumped, compacted, and covered in landfills. Anaerobic bacteria thrives in the oxygen-free environment, resulting in the decomposition of the organic materials and the production of primarily carbon dioxide and methane. Carbon dioxide is likely to leach out of the landfill because it is soluble in water. Methane, on the other hand, which is less soluble in water and lighter than air, is likely to migrate out of the landfill. Landfill gas energy facilities capture the methane (the principal component of natural gas) and combust it for energy.

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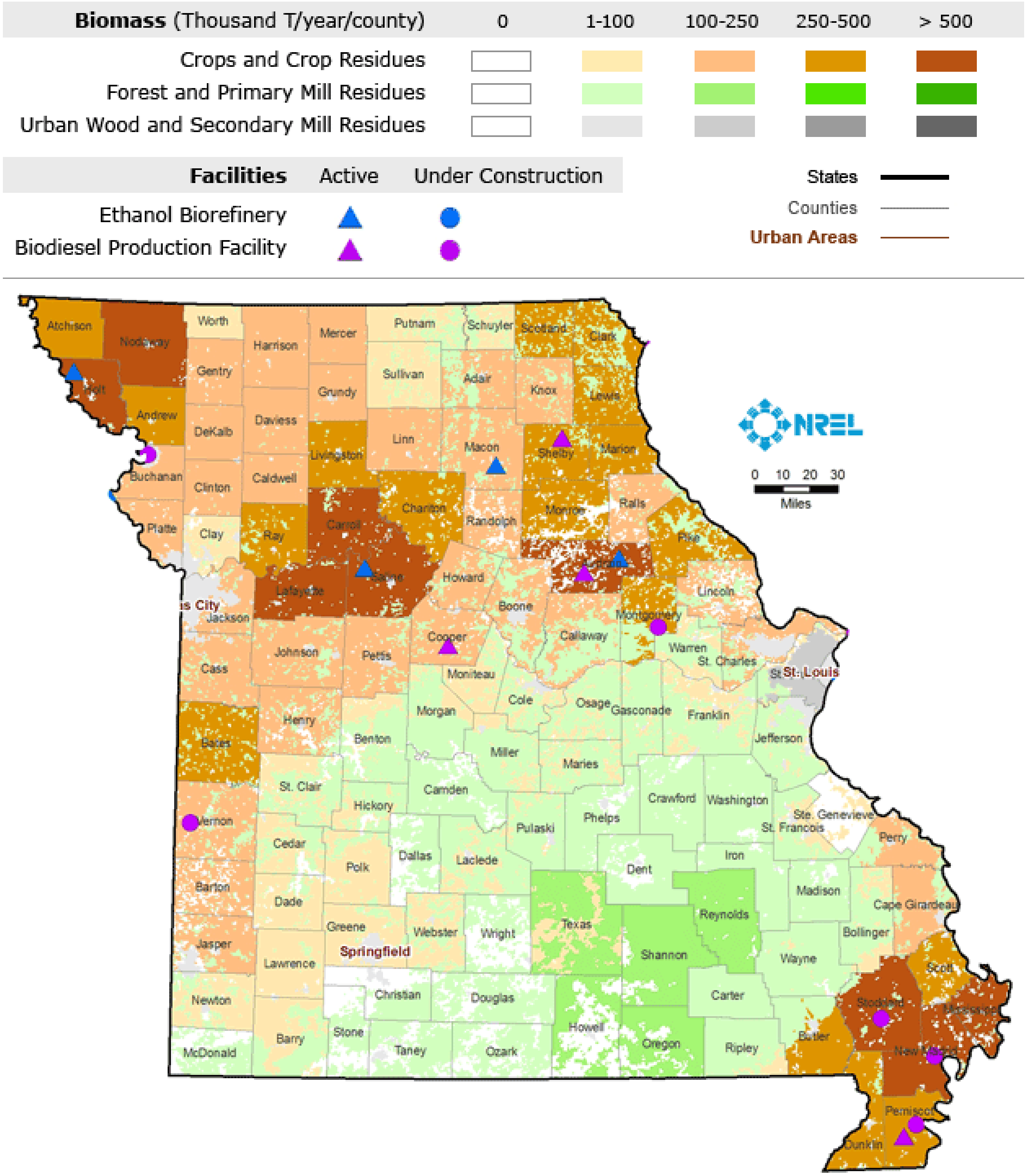
[8] U.S. Department of Energy, Energy Efficiency and Renewable Energy,"Biomass Topics," http://www.eere.energy.gov/RE/biomass.html.

[9] Barry, Barton, Cedar, Christian, Dade, Dallas, Greene, Hickory, Jasper, Lawrence, McDonald, Newton, Polk, St. Clair, Stone, and Taney.

[10] Missippi_band_choctaw_tep_nov03.pdf.

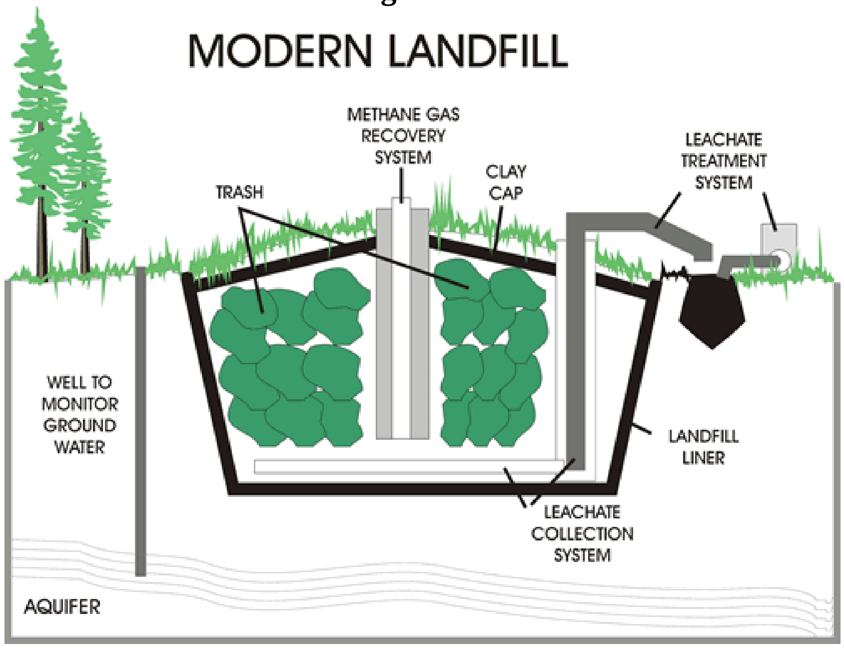
[11] "Landfill Gas," U.S. Department of Energy – Energy Information Administration, http://www.eia.doe.gov/cneaf/solar.renewables/page/landfillgas/landfillgas.html.

Figure 5-6
Biomass Resources in Missouri



Source: National Renewable Energy Laboratory

Figure 5-7



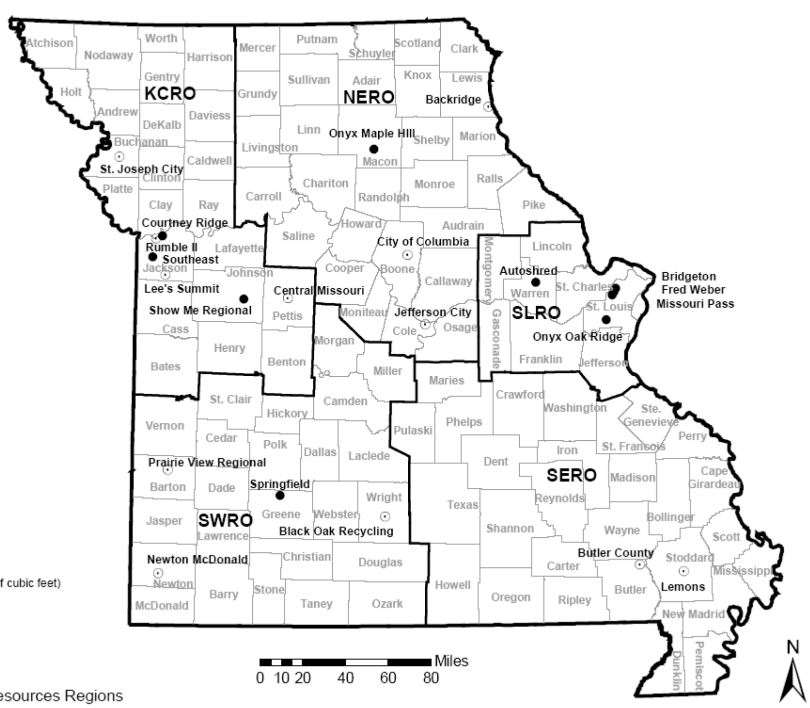
Source: The National Energy Education Project

Figure 5-8

Landfill Gas Energy Potential Based on 2005-2014 Minimum Gas Flows

Landfill Name	MW	NG (Mcf)
SLRO		
Autoshred	2.4	228.6
Bridgeton	8.4	802.9
Fred Weber *	9.0	856.2
Missouri Pass	5.0	478.6
Onyx Oak Ridge *	5.2	499.3
SWRO		
Black Oak	1.4	137.2
Newton McDonald	0.6	52.8
Prarieview	1.2	118.8
Springfield	2.7	261.2
SERO		
Butler County	1.7	158.7
Lemons East	1.6	154.8
NERO		
Backridge	0.9	84.1
City of Columbia	0.9	83.8
Jefferson City	2.0	186.3
Onyx Maple Hill	2.5	241.3
KCRO		
Central Missouri	1.4	130.6
Courtney Ridge	4.6	433.6
Lee Summit	2.0	195.0
Rumble II *	1.7	161.6
Show Me Regional	2.8	268.3
Southeast	3.5	332.2
St. Joseph	1.0	90.9

MW - equivalent generating capacity in megawatts
NG (Mcf) - equivalent quanity of natural gas (millions of cubic feet)



LEGEND

Landfills

- Highest gas flows
- Moderate gas flows
- Missouri Department of Natural Resources Regions
  - KCRO - Kansas City Regional Office
  - NERO - Northeast Regional Office
  - SERO - Southeast Regional Office
  - SLRO - St Louis Regional Office
  - SWRO - Southwest Regional Office
- County boundary

* Landfill includes existing projects

Source: U.S. Environmental Protection Agency Landfill Methane Outreach Program modeling estimates, June 2004

Missouri Department of Natural Resources

5.2.2.3 Biomass – Additional Biomass

Additional biomass has been interpreted by Empire to mean wood waste and municipal solid waste. The U.S. Department of Energy – Energy Information Administration reports that wood waste, consisting of forest lands, private land clearing, urban tree and landscape residues, manufacturing and wood processing wastes, as well as construction and demolition debris can serve as a source of fuel to generate electricity. Municipal solid waste (garbage) can be sorted and the combustible products that are not recycled can be used to generate electricity.

Figure 5-9
Biomass – Wood Waste Facility

The biomass characteristics modeled in the optimization planning are shown on Table 5-9.

Table 5-9
Biomass Performance Parameters

Parameter	Value
Earliest feasible year of installation	2015
Size, MW (net)	5
Full load heat rate, Btu/kWh	10,000
Capital cost, $/kW (2010 $)	3766
Fixed O&M, $/kW-year	64.45
Variable O&M, $/MWh	6.71
Equivalent Forced Outage Rate, %	5
SO_2 Emissions, lbs/MMBtu	0.01
NO_x Emissions, lbs/MMBtu	0.01
CO_2 Emissions, lbs/MMBtu	210

5.2.3 Solar

The solar radiation that comes from the sun can be harnessed and converted to electricity in two primary ways: solar photovoltaics (solar PV) and concentrating solar power (CSP). PVs or solar cells change sunlight directly into electricity. A typical PV cell is shown in Figure 5-10. The potential for PV applications as reported by the National Renewable Energy Laboratory is shown in Figure 5-11.

Figure 5-10
Photovoltaic cell

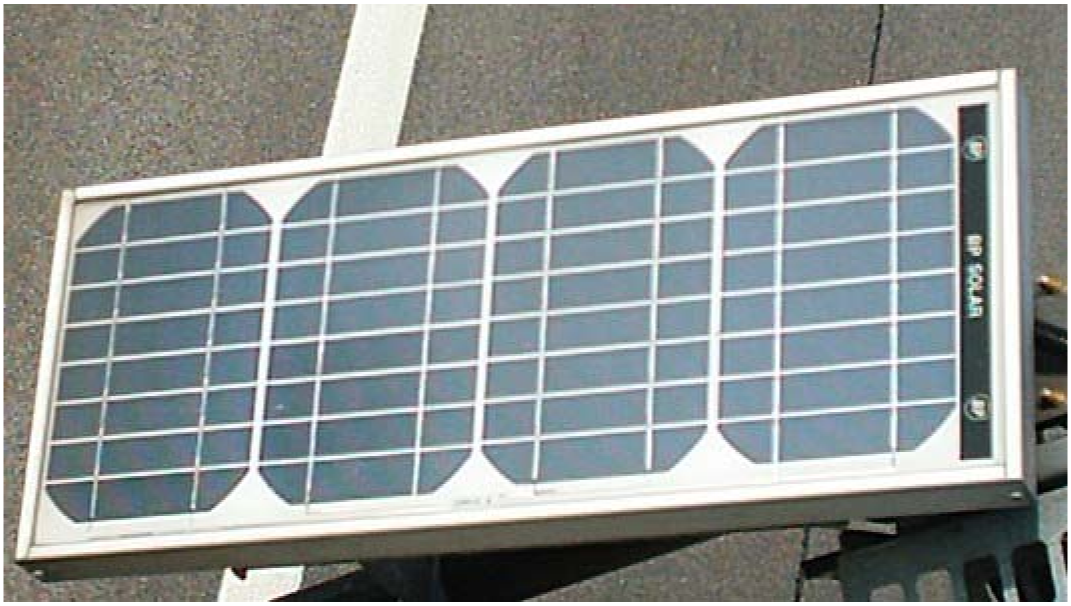
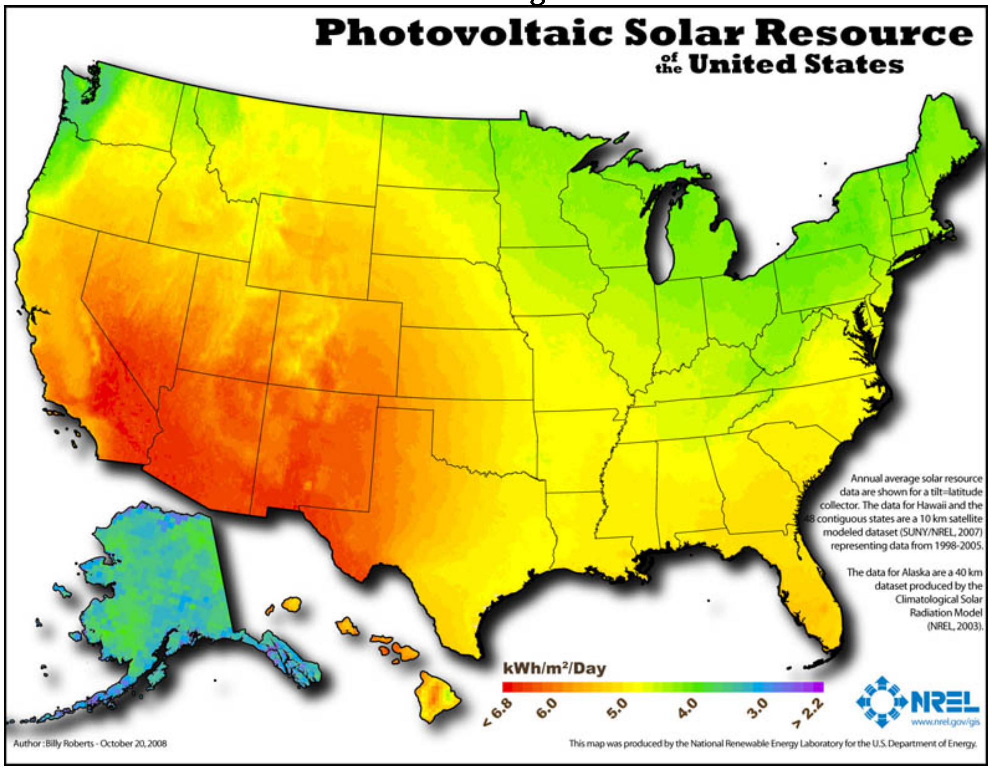


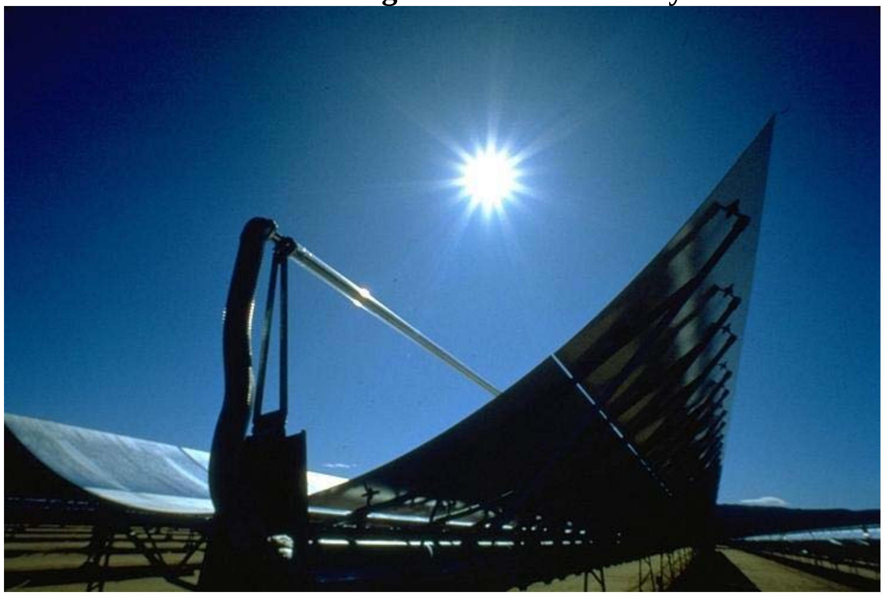
Figure 5-11



Source: National Renewable Energy Laboratory

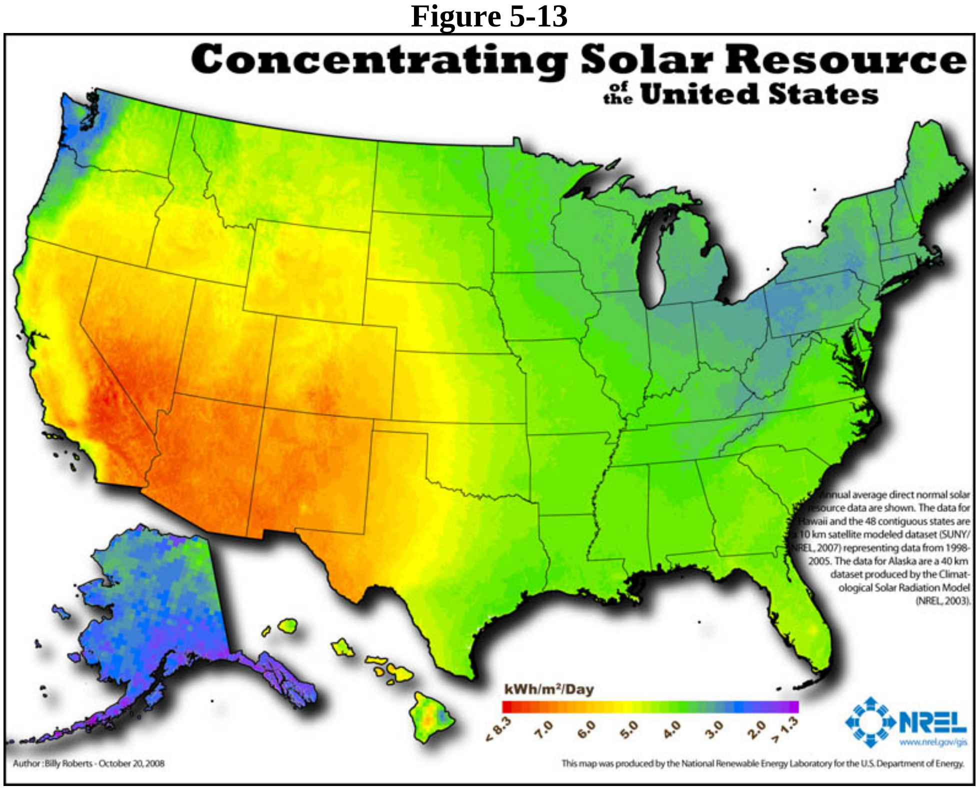
Concentrating solar power (CSP) is one of the technologies classified as solar thermal. Any solar thermal technology involves a process where the solar energy is used to heat a fluid thereby creating steam that drives a turbine to generate electricity. The existing CSP facilities in the U.S. are found in California, Arizona, and Nevada. An example of a CSP facility is shown in Figure 5-12.

Figure 5-12
Concentrating Solar Power Facility



The potential for concentrating solar power as developed by the National Renewable Energy Laboratory is shown in Figure 5-13. Missouri has lower CSP potential than the potential for PV applications.

Figure 5-13



Source: National Renewable Energy Laboratory

Residential solar PV was considered as a potential program in the DSM analysis. It was screened out as not being cost effective. The data used for modeling solar thermal in the IRP are shown in Table 5-10.

Table 5-10
Solar Performance Parameters

Parameter	Solar Thermal
Earliest feasible year of installation	2015
Size, MW (net)	100
Capital cost, $/kW (2010 $)	5069.96
Fixed O&M, $/kW-year	57.30

6.0 Transmission

Empire believes that at least some of the resources that will be required over the planning horizon may have significant transmission costs associated with them. Empire is a member of the Southwest Power Pool (SPP) and, as such, is now reliant on the SPP's determination of which transmission lines will be built and on what schedule. As a member of SPP, Empire is assigned a cost sharing allocation of all lines that are built in the SPP. That cost allocation varies per line.

The SPP conducts three studies directly associated with transmission planning: Large Generation Interconnect Studies, Aggregate Transmission Service Studies, and the SPP Transmission Expansion Plan (STEP). The Large Generation Interconnect Study determines all of the modifications needed to connect a new generator into the transmission system. The Aggregate Transmission Service Studies determine system upgrades required to grant transmission service from a generation source to a load. The STEP determines upgrades required for a reliable transmission system and provides a screening of potential economic projects. Until a specific line is submitted to the SPP, it is not possible to estimate what the actual cost to Empire will be. Therefore, Empire modeled a generic transmission cost adder for each alternative resource examined in this IRP.

As of January 2005, the SPP uses a Federal Energy Regulatory Commission (FERC)-approved process called an Aggregate Transmission Service Study. In this process, SPP combines all long-term point-to-point and all long-term network resource transmission service requests received during a sequential four-month open season into a single aggregate transmission service study. Such an aggregated analysis should result in a more optimal expansion of the SPP transmission system than occurred previously with less aggregated analyses.

Empire actively participates in transmission planning in the SPP through committee membership, attending meetings, participation as a customer and a transmission owner in the development and implementation of all of SPP's transmission studies, and other methods. In two recent cases involving the Open Access Transmission Tariff in the SPP, Empire filed protests with the FERC. These cases involved the OATT "Highway/Byway" cost allocation methodology and the modified transmission planning process referred to as the Integrated Transmission Plan (ITP).

For the purposes of Empire's 2010 IRP, Empire did assign transmission costs on a $/kW basis for each candidate resource examined in this IRP. The cost was $90/kW in 2010 $, escalating at 2.5% per year.

Empire is providing information in this IRP on future transmission projects within Empire's control area that are planned by the SPP in the STEP (see Appendices A and B). This information has been approved by the SPP Board of Directors.

Since not all of Empire's planned construction projects are accounted for in the STEP, details from Empire's 2010-2014 Construction Budget for planned transmission and distribution projects are presented in Appendix C. Empire's 2010-2014 Transmission and Construction Budget includes transmission system additions, transmission system rebuilds, distribution system additions, distribution system rebuilds, and distribution system extensions and service.

Plans for transmission projects within the SPP change frequently as conditions on utility systems, including Empire's, change.

6.1 Losses

Empire works to reduce system losses in a variety of ways. One is by evaluating losses of power transformers at the time of purchase. As old transformers are replaced, newer transformers have lower levels of losses. Another is by strategically installing capacitor banks on the distribution system. In the late 1990s, Empire undertook a power factor campaign targeting installation of capacitor banks around the system. As can be seen in Table 6-1, Empire's total system losses have decreased over time – its 2008 electric system losses were less than 7% as compared to losses of over 8% in 1995.

Table 6-1
Historical System MWh Losses[12]

Year	Firm Sales (MWh)	Total Losses (MWh)	% Annual Losses	% 5-Year Rolling Average Losses
1995	3,640,222	291,936	8.02	
1996	3,886,687	312,745	8.05	
1997	3,928,767	315,441	8.03	
1998	4,162,607	303,175	7.28	
1999	4,163,824	304,747	7.32	
2000	4,424,768	366,028	8.27	7.79
2001	4,494,199	304,067	6.77	7.53
2002	4,566,262	334,287	7.32	7.39
2003	4,594,856	347,676	7.57	7.45
2004	4,628,759	338,035	7.30	7.45
2005	4,923,486	361,858	7.35	7.26
2006	5,049,599	273,483	5.42	6.99
2007	5,118,460	356,396	6.96	6.92
2008	5,124,277	353,204	6.89	6.78

[12] Management Applications Consulting, Inc. "2008 Analysis of System Losses," October 2009.

6.2 Smart Grid

In March 2010, Empire assembled a team to develop a pilot program that would research and test the available metering products and technologies for an advanced metering infrastructure system such as would be required for Smart Grid. The main benefits of such a system are automated meter reading, on-demand meter reads, and instant outage notification.

The team determined it would first need to visit with and learn from a number of manufacturers, vendors, and other utility companies. It was also necessary to identify the required interfaces and to then define the corporate resources needed to ensure a successful pilot implementation.

The proposed pilot program will include residential, commercial, and industrial customers, and will cover single-phase and three-phase applications. The plan is for the pilot program to implement two different communication technologies via two separate phases. The scale, location, and timeline are pending completion as of September 2010.

7.0 Screening Analysis

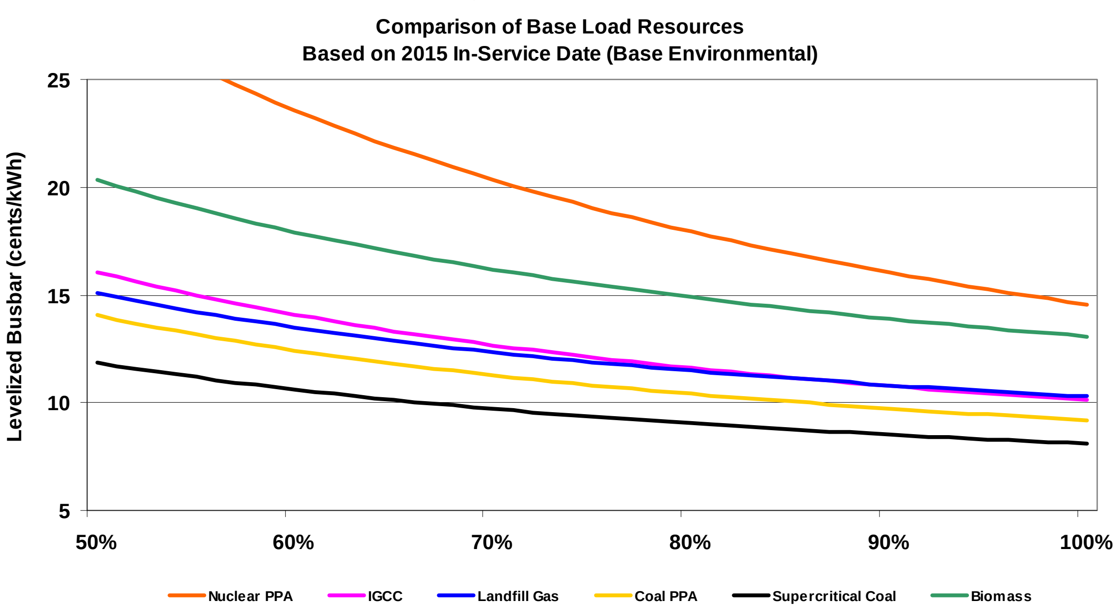
Two sets of screening cost curves were developed: one for base environmental costs and one for probable environmental costs. The costs are expressed in nominal dollars. The cost curves presented are for 2015 as that is roughly the first year that Empire needs to consider new supply-side resources. The supply-side alternatives have been ranked using a spreadsheet model that computes levelized busbar costs. The levelized busbar costs considers capital, fuel and operating and maintenance costs for each technology and calculates costs for a range of capacity factors for each technology. These costs do not reflect how a specific technology would operate within the Empire generating system but instead is a stand-alone per unit cost calculated on a cents per kWh basis.

7.1 Base Environmental Costs

The first series of screening curves assumed base environmental costs. Screening curves are presented for baseload resources, intermediate resources, intermittent resources, and peaking resources. Rankings can be deduced by examining the curves at a specific capacity factor.

Base Load Resources: Figure 7-1 shows the screening curve for baseload resources over the range of 50% to 100% capacity factor. Technologies considered included coal, landfill gas, nuclear, IGCC and biomass.

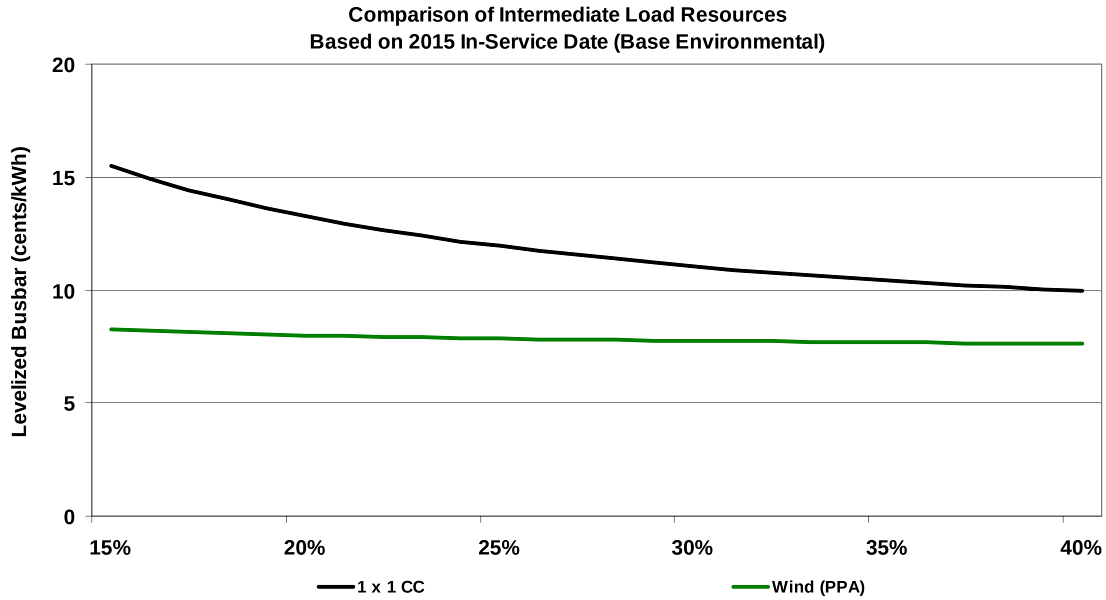
Figure 7-1
Baseload Screening Curves – Base Environmental



Source: Venytx

Intermediate Load Resources: The cost curve for the intermediate load resources shown on Figure 7-2 considers a capacity factor range of 15% to 40%. The technologies considered were a 1 x 1 combined cycle and wind.

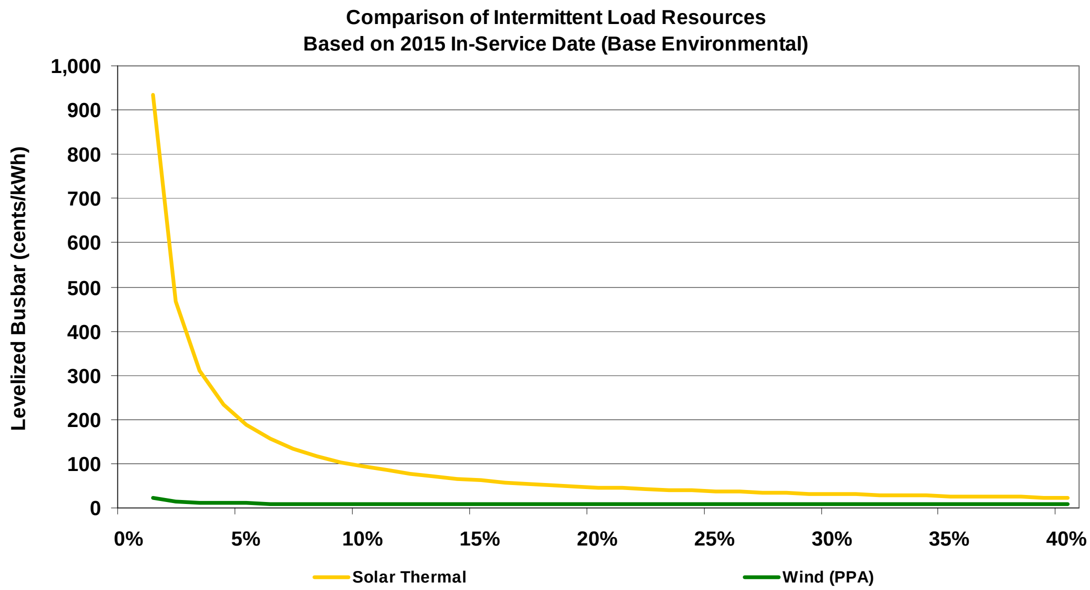
Figure 7-2
Intermediate Screening Curves – Base Environmental



Source: Venytx

Intermittent Load Resources: The screening curves for the intermittent load resources shown on Figure 7-3 include solar thermal and wind.

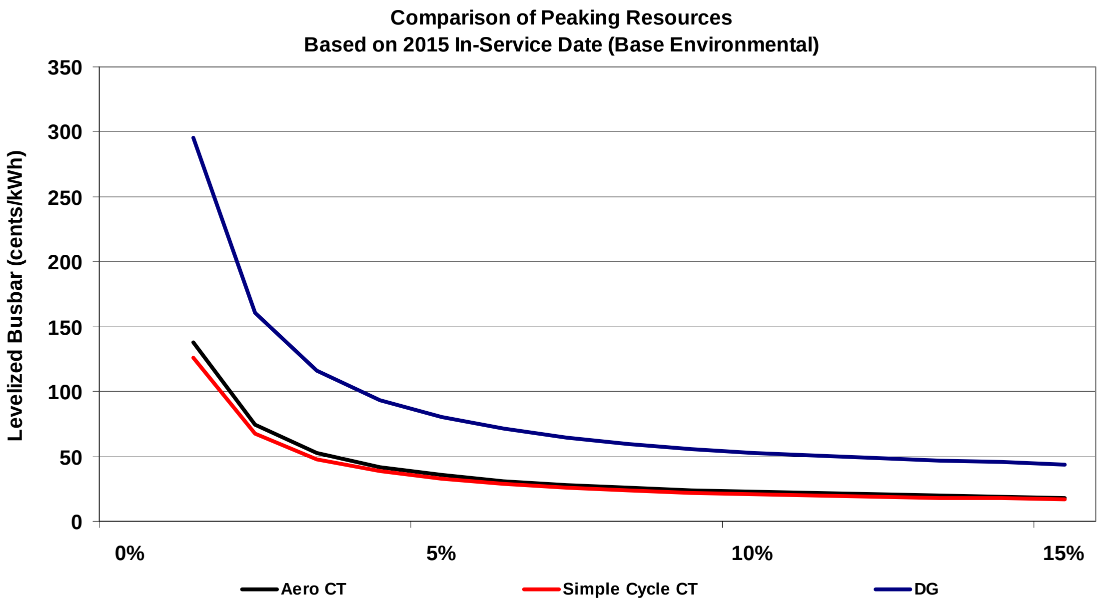
Figure 7-3
Intermittent Screening Curves – Base Environmental



Source: Venytx

Peaking Load Resources: The screening curves for the peaking load resources shown in Figure 7-4 include combustion turbines and distributed generation.

Figure 7-4
Peaking Screening Curves – Base Environmental



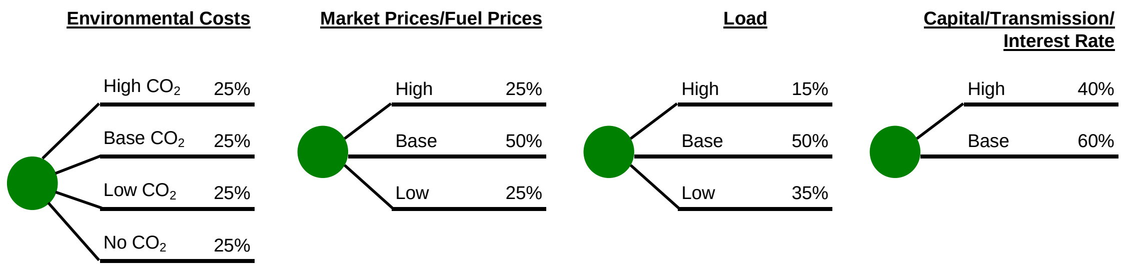
Source: Venytx

7.2 Probable Environmental Costs

The second series of screening curves assumed probable environmental costs. Screening curves are presented for baseload resources, intermediate resources, intermittent resources, and peaking resources. Rankings can be determined through an examination of the relative values of the cost curves.

Ventyx used the non-zero probabilities for each scenario shown in Figure 7-5 to "weight rank" the supply-side alternatives when considering probable environmental costs. The cost of fuel was correlated to the emission costs for each of the scenarios.

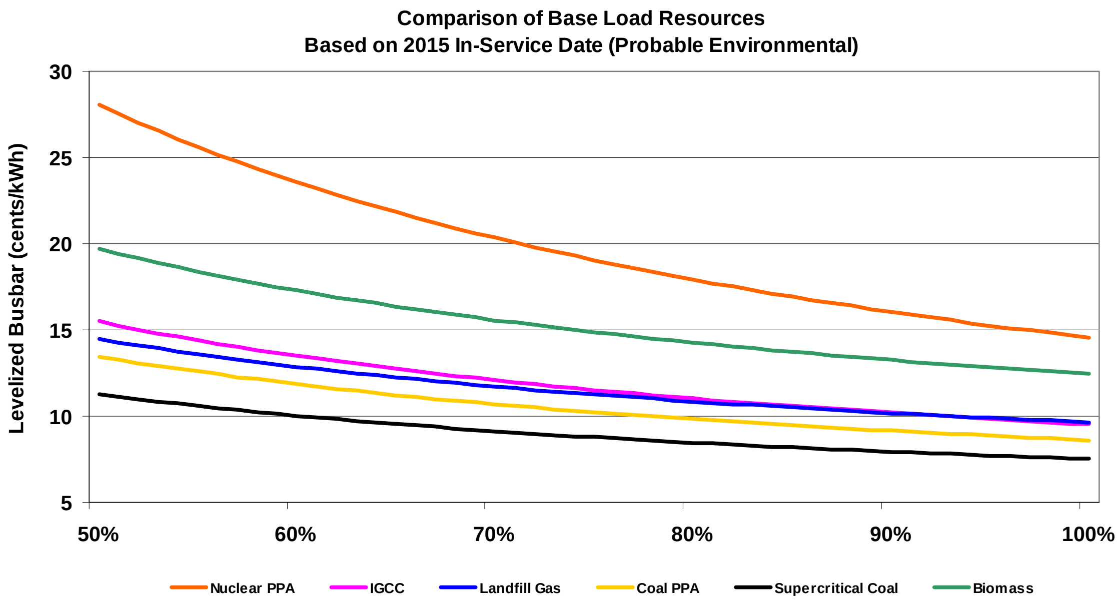
Figure 7-5
Critical Uncertain Factors



Source: Venytx

Base Load Resources: Figure 7-6 shows the cost curves for baseload resources over the range of 50%-100% capacity factor using the probable environmental costs. Technologies considered included coal, landfill gas, nuclear, IGCC and biomass.

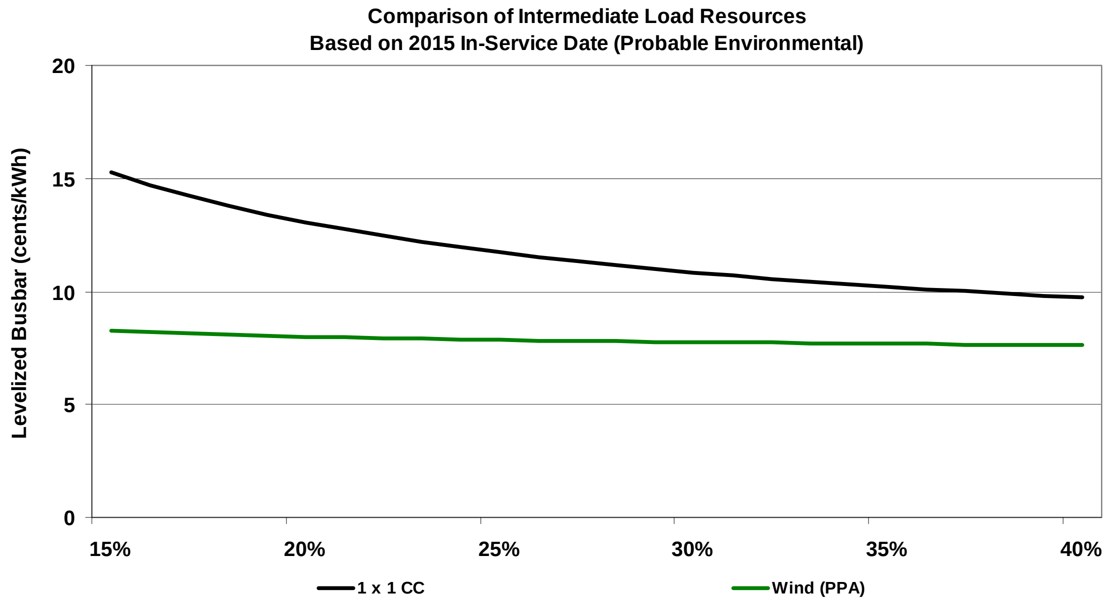
Figure 7-6
Baseload Screening Curves – Probable Environmental



Source: Venytx

Intermediate Load Resources: The cost curve for the intermediate load resources shown on Figure 7-7 considers a capacity factor range of 15% to 40%. The technologies considered were combined cycle and wind.

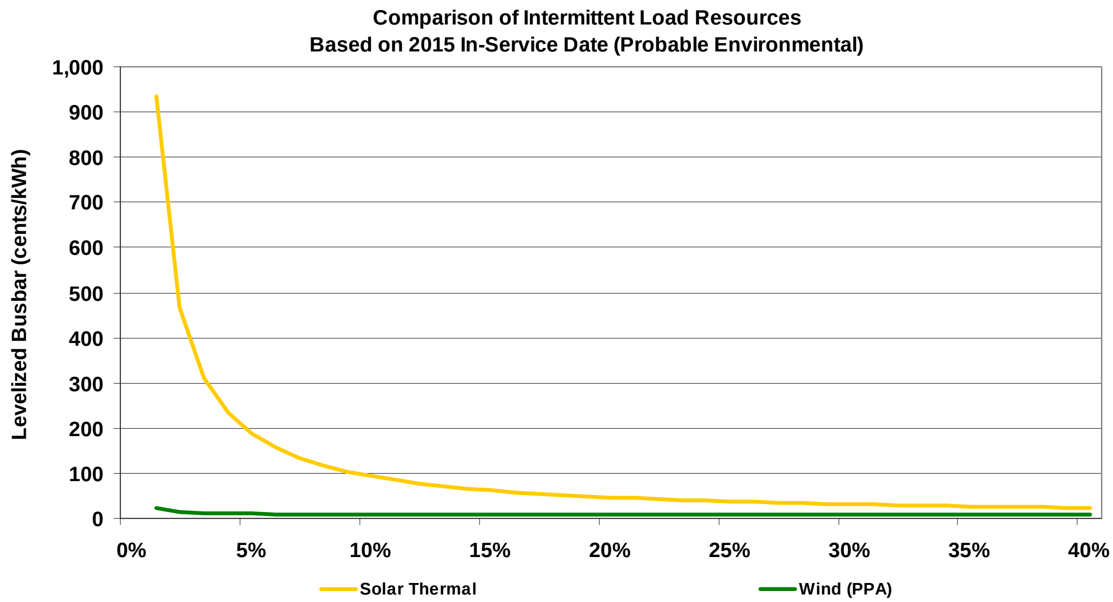
Figure 7-7
Intermediate Screening Curves – Probable Environmental



Source: Venytx

Intermittent Load Resources: The screening curves for the intermittent load resources shown on Figure 7-8 include solar thermal and wind.

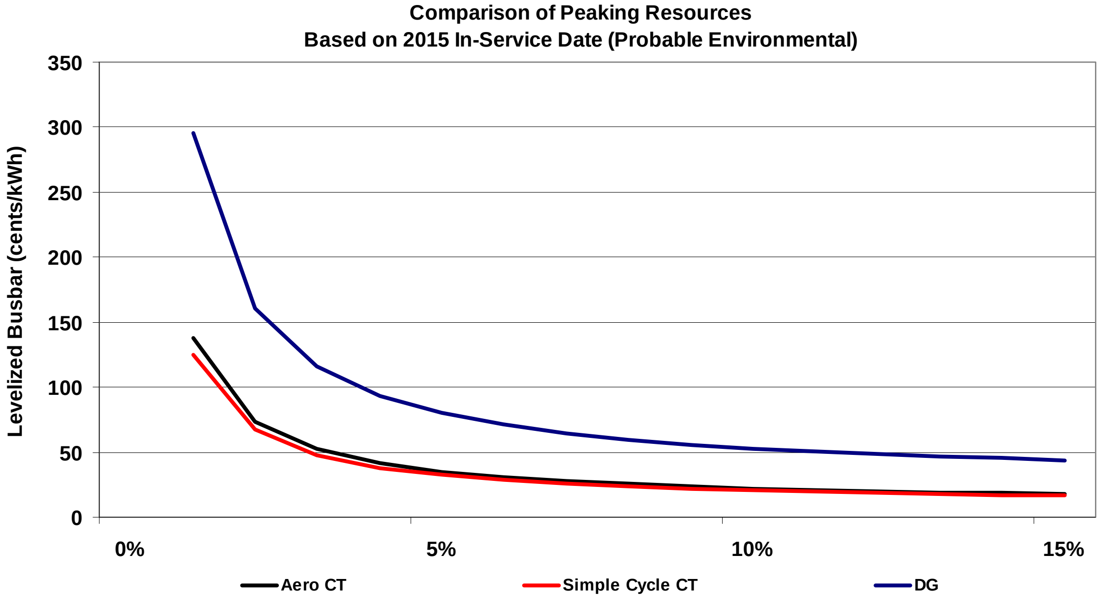
Figure 7-8
Intermittent Screening Curves – Probable Environmental



Source: Venytx

Peaking Load Resources: The screening curves for the peaking load resources shown in Figure 7-9 include combustion turbines and distributed generation.

Figure 7-9
Peaking Screening Curves – Probable Environmental



Source: Venytx

Appendix A– SPP Transmission Expansion Plan Projects

SPP Board of Directors Approved Appendix A projects January 26, 2010

NTC_ID	UID	PID	Project Type	Project Description/Comments	Cost Estimate	Facility Owner	In-Service Date	2009 STEP Date	2009 STEP BOD Action	Latest Letter of notification to construct issue date	From Bus Name	To Bus Name	Circuit
						Year 2010							
20000	10294	229	regional reliability	Reconductor 5.14 mile Bentonville 279th St. - East Centerton 161 kV with 1590 conductor.	$5,017,000	AEP	06/01/10	M		02/13/08	Bentonville 279th Street 161 kV	East Centerton 161 kV	1
20016	10440	343	regional reliability	Replace 69 kV switches at Winnsboro and reset CT ratios and relay settings.	$90,000	AEP	06/01/10	M		01/16/09	Winnsboro 69 kV	Magnolia Tap 69 kV	1
20016	10443	346	regional reliability	Replace Quitman 69 kV bus, switches and jumpers. Change CT and relay settings.	$185,000	AEP	06/01/10	M		01/16/09	Forest Hills 69 kV	Quitman 69 kV	1
	11185	893	zonal - sponsored	Restore existing 9.2 mile radial de-energized 138 kV line to service. Build 138-4.16 kV station at Enogex Wilberton.	$1,456,000	AEP	07/01/10				Lone Oak 138 kV	EnoGex Wilberton 138 kV	1
	11186	894	zonal - sponsored	Build new 0.6 mile double circuit tap from the existing Perdue - Lake Hawkins 138 kV line to a new 138 kV Exxon - Mobil Hawkins switching station.	$3,550,000	AEP	12/01/10				Exxon-Mobil Hawkins 138 kV	Perdue 138 kV	1
	11187	894	zonal - sponsored	Build new 0.6 mile double circuit tap from the existing Perdue - Lake Hawkins 138 kV line to a new 138 kV Exxon - Mobil Hawkins switching station.	$3,550,000	AEP	12/01/10				Exxon-Mobil Hawkins 138 kV	Lake Hawkins 138 kV	1
20016	10652	507	transmission service	Rebuild 3.24 miles of 1272 AAC with 2156 ACSR. Replace 3 138 kV switches, breaker jumpers, and reset CTs at Arsenal Hill. Replace 2 138 kV switches and jumpers at Fort Humbug.	$5,428,300	AEP	06/01/10	M		01/16/09	Arsenal Hill 138 kV	Fort Humbug 138 kV	1
20016	50155	30147	transmission service	Replace auto and 69 kV breaker and switches.	$3,005,700	AEP	06/01/10	M		01/16/09	Arsenal Hill 138 kV	Arsenal Hill 69 kV	2
20016	50154	30146	transmission service	Replace auto and 69 kV breaker and switches.	$3,005,700	AEP	06/01/10	M		01/16/09	Arsenal Hill 138 kV	Arsenal Hill 69 kV	1
20016	50161	30153	transmission service	Replace four (4) switches and upgrading bus work.	$200,000	AEP	06/01/10	M		01/16/09	Longwood 345 kV	Longwood 138 kV	1
	10862	657	regional reliability	Replace (3) 600 A switches with 1200 A switches.	$150,000	AEP		06/01/10	NTC		Pryor Junction 115 kV	Pryor Junction 69 kV	1
19959	10375	289	transmission service	Replace wave trap at Clinton City Substation.	$135,400	AEP	06/01/10	M		10/17/06	Clinton City 69 kV	Foss Tap 69 kV	1
20000	10380	294	regional reliability	Replace Mineola 2 Switches & Breaker	$339,000	AEP	06/01/10	M		02/13/08	North Mineola 69 kV	Mineola 69 kV	1
	10296	231	Generation Interconnect	Build new 34 mile Turk - SE Texarkana 138 kV line and add SE Texarkana 138 kV terminal.	$25,590,000	AEP	12/31/10	M			Turk 138 kV	SE Texarkana 138 kV	1
	10297	232	Generation Interconnect	Build new 24 mile Turk - Sugar Hill 138 kV line and add Sugar Hill 138 kV terminal.	$18,427,000	AEP	12/31/10	M			Turk 138 kV	Sugar Hill 138 kV	1
19953	10381	295	transmission service	AEPW to reconductor 1.09 miles of 795 ACSR with 1590 ACSR. (Also, Westar to rebuild 3.93 miles of 795 ACSR with 1590 ACSR.) These ratings are just for the AEP facilities.	$1,008,000	AEP	06/01/10	M		06/26/07	Coffeyville T 138 kV	Dearing 138 kV	1
20000	10383	297	regional reliability	Reconductor Quitman - Westwood 69 kV 3.91 miles of 2/0 with 795 ACSR	$3,827,000	AEP	06/01/10	M		02/13/08	Quitman 69 kV	Westwood 69 kV	1
20016	10382	296	transmission service	Rebuild/reconductor 5.17 mile Dyess - Elm Springs 161 kV with 2156 ACSR.	$6,252,000	AEP	06/01/10	M		01/16/09	Dyess 161 kV	Elm Springs 161 kV	1
20016	10445	348	regional reliability	Replace 161 kV breaker, switches and CTs at Dyess.	$224,000	AEP	06/01/10	M		01/16/09	Dyess 161 kV	Tontitown 161 kV	1
20027	10784	613	regional reliability	Replace switch at Diana for higher winter rating of 287/316 MVA. Summer rating unchanged.	$100,000	AEP	12/01/10	M		01/27/09	Diana 138 kV	Lone Star South 138 kV	1
20027	10378	292	regional reliability	Reconductor 2.66 mile Greggton - Lake Lamond 69 kV with 1272 ACSR.	$4,047,000	AEP	06/01/10	M		01/27/09	Greggton 69 kV	Lake Lamond 69 kV	1
20027	10617	480	regional reliability	Build new 4 mile AEP Snyder - WFEC Snyder 138 kV. WFEC to connect AEP Snyder to WFEC Snyder. AEP to provide 138 kV terminal at AEP Snyder.	$800,000	AEP	12/31/10	M		01/27/09	AEP Snyder 138 kV	WFEC Snyder 138 kV	1
	11011	767	regional reliability	Convert 17 mile Canadian River - McAlester City line from 69 kV to 138 kV.	$17,000,000	AEP		06/01/10	NTC		Canadian River 138 kV	McAlester City 138 kV	1
	11012	767	regional reliability	Tap Pittsburg - Muskogee 345 kV about 33 miles north of the Pittsburg station and step down to 138 kV with a 450 MVA auto.	$8,500,000	AEP		06/01/10	NTC		Canadian River 345 kV	Canadian River 138 kV	1
	11183	767	regional reliability	Rebuild McAlester City Tap, double circuiting existing line, eliminate the 'T' at McAlester City North Tap.	$2,900,000	AEP		06/01/10	NTC		McAlester City 138 kV	Dustin 138 kV	1
	11184	767	regional reliability	Rebuild McAlester City Tap, double circuiting existing line, eliminate the 'T' at McAlester City North Tap.	$2,900,000	AEP		06/01/10	NTC		McAlester City 138 kV	McAlester City North Tap 138 kV	1
	50286	30248	regional reliability - non OATT	Install 2 Blocks of 14.4 Mvar	$1,166,400	CRE		06/01/10			CR-S. Midland 138 kV		
	50287	30249	regional reliability - non OATT	Install 2 Blocks of 7.2 Mvar	$583,200	CRE		06/01/10			CR-Salem		
20011	10271	212	regional reliability	Reconductor 3 mile 69 kV line from 336.4 kcmil ACSR to 477 kcmil ACSS/TW	$1,485,000	CUS	06/01/10	M		02/13/08	Norton 69 kV	Neergard 69 kV	1
	10436	339	zonal - sponsored	Step-Up Transformer for new SWPS #2 (DNR)	$3,200,000	CUS	10/01/10	M			Southwest 161 kV	Southwest 2 20 kV	1
	10275	216	regional reliability - non OATT	Rayburn Project -- Build new 10 mile Ben Wheeler - Barton Chapel 138 kV.		DETEC	12/31/10	M			Ben Wheeler (Wood County EC) 138 kV	Barton's Chapel (Rayburn County) 138 kV	1
20010	50084	30078	Zonal Reliability	Install (3) 22 Mvar capacitor banks for a total of 66 Mvar at Riverside Sub #438.	$2,600,000	EDE	12/01/10	M		02/13/08	SUB 438 - Riverside 161 kV		
20049	10495	382	regional reliability	Change CT setting on Breaker #6973 at Baxter #271 to 800/5 ratio.	$50,000	EDE	06/01/10	M		09/18/09	SUB 404 - Hockerville 69 kV	SUB 271 - Baxter Springs West 69 kV	1
20036	10547	421	regional reliability	Change CT ratio on breaker #6936 at Aurora Substation 124.	$5,000	EDE	06/01/10	M		01/27/09	SUB 124 - Aurora H. T. 69 kV	SUB 152 - Monett H.T. 69 kV	1
19969	10435	338	transmission service	Rebuild 1.7 mile Neosho South Jct. - Neosho SPA 161 kV from 336 ACSR to 795 ACSR and replace terminal equipment	$1,215,000	EDE	06/01/10	M		09/22/06	SUB 184 -Neosho South Junction 161 kV	Neosho (SWPA) 161 kV	1
20049	10641	496	regional reliability	Replace 600 amp disconnect switches with a minimum 1,200 amp units and replace leads on Breaker #6965 at Sub #64 and #6932 at Sub #145.	$55,000	EDE	06/01/10	06/01/15		09/18/09	SUB 145 - Joplin West 7TH 69 kV	SUB 64 - Joplin 10TH ST. 69 kV	1
20053	50225	30221	regional reliability	Add 12 Mvar cap bank at Ralph Green	$486,000	GMO	06/01/10			09/18/09	Ralph Green 69 kV		
20034	10768	601	regional reliability	Replace wavetraps at Longview and Grandview East on the Grandview - Longview 161kV line.	$50,000	GMO	06/01/10	M		01/27/09	Grandview East 161 kV	Longview 161 kV	1
20034	10816	628	regional reliability	Replace wavetrap at Platte City.	$50,000	GMO	12/01/10	M		01/27/09	Platte City 161 kV	Smithville 161 kV	1
20034	10832	635	regional reliability	Build a new Edmond 161/69/34.5 kV substation between the Cook and Lake Road 161 kV substations that will pick up the loads supplied by the Lake Road 161/34.5 kV sources.	$5,405,930	GMO	07/01/10	M		01/27/09	Cook 161 kV	Lake Road 161 kV	1
20053	50226	30222	regional reliability	Reset the overcurrent relay at South Harper 69 kV substation to open South Harper - Freeman 69 kV line upon reaching thermal limit of Freeman – Anaconda – Harrisonville West 69 kV line	$20,000	GMO	06/01/10			09/18/09			
20028	50078	30072	regional reliability	Install (3) 7.2 Mvar capacitors for a total of 21.6 Mvar at Afton 69 kV bus.	$800,000	GRDA	06/01/10	M		01/27/09	Afton 69 kV		
	10389	302	zonal - sponsored	Tap the GRDA 1-Flint Creek 345 kV line and build a 345/161 transformer. Then build a 161 kV line down to Siloam Springs.	$3,210,200	GRDA	06/01/10	M			Siloam Springs Tap 161 kV	Siloam City 161 kV	1
20001	10388	301	regional reliability	Add second 161/69 kV 75 MVA autotransformer at Sallisaw	$3,000,000	GRDA	06/01/10	M		02/13/08	Sallisaw 69 kV	Sallisaw 161 kV	2
20009	50083	30077	Zonal Reliability	New Craig 50 Mvar capacitor bank.	$1,057,630	KCPL	06/01/10	M		02/13/08	Craig 161 kV		
	10363	279	zonal - sponsored	Replace Lenexa Circuit Switcher R1-4 with 2000 Amp Breaker	$192,000	KCPL	06/01/10	M			Craig 161 kV	Lenexa 161 kV	1
	10256	200	zonal - sponsored	New Boulevard sub and new 161kV line	$4,352,600	KCPL	09/30/10	M			Terrace 161 kV	Boulevard 161 kV	1
	10257	201	zonal - sponsored	New 161kV line	$4,750,000	KCPL	03/30/10	M			Crosstown 161 kV	Boulevard 161 kV	1
	10951	714	regional reliability	Replace 200 A CT and 400 A wavetrap at Mayview to increase line rating.	$5,000	KCPL		06/01/10	NTC		Amoco Pipeline 69 kV	Mayview Tap 69 kV	1
	11144	866	zonal - sponsored	Rebuild Sheldon to 20th & PIO. Upgrade based on condition of facility.	$621,875	LES	05/31/10	M			Sheldon 115 kV	20th & PIO 115 kV	1
	11145	867	zonal - sponsored	Rebuild 3rd & Vandn to 20th & PIO. Upgrade based on condition of facility.	$790,625	LES	05/31/10	M			3rd & Vandn 115 kV	20th & PIO 115 kV	1
20052	50223	30219	transmission service	Rebuild approximately 14.5 miles of 34.5 kV line between Rice County and Ellinwood to achieve a minimum 600 amp emergency rating	$1,812,500	MIDW	06/01/10			09/18/09			
20054	50068	30062	regional reliability	Add 138 kV 20 Mvar cap bank at Harper	$1,400,000	MKEC	05/01/10	M		09/18/09	Harper 138 kV		
20007	50067	30061	regional reliability	Install (2) 12 Mvar capacitor banks at Pratt 115kV.	$2,300,000	MKEC	03/01/10	M		02/13/08	Pratt 115 kV		
	50202	30195	zonal - sponsored	Add one 7.2 Mvar cap at Westminster	$375,000	NPPD	06/01/10	M			Westminster 34.5 kV		
	10961	744	transmission service	Replace Canaday transformer.	$5,000,000	NPPD	11/01/10	M			Canaday 115 kV	Canaday 230 kV	1
	10772	603	regional reliability	Build 2.4 miles of new 115 kV line from Kansas/Nebraska state line to Steele City.	$3,000,000	NPPD	10/01/10	06/01/10	NTC		Knob Hill 115 kV	Steele City 115 kV	1
	10775	605	regional reliability		$5,000,000	NPPD	06/01/10	M	NTC		N. Platte 230 kV	N. Platte 115 kV	2
	11160	606	regional reliability	Build new 67 mile Columbus East - NW 68th & Holdrege 345 kV line.		NPPD	04/01/10	M	NTC		Columbus East 345 kV	NW 68 and Holdrege 345 kV	1
	11161	606	regional reliability	Build new 12 mile Columbus East - Shell Creek 345 kV line.		NPPD	10/13/09	M	NTC		Shell Creek 345 kV	Columbus East 345 kV	1
	10970	606	regional reliability	Upgrade Columbus East - Columbus line to 238 MVA.		NPPD	04/01/10	M	NTC		Columbus East 115 kV	Columbus 115 kV	1
	10971	606	regional reliability	Upgrade Pawnee Lake - Seward line to 120 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.		NPPD	04/01/10	M	NTC		Pawnee Lk 115 kV	Seward 115 kV	1
	10972	606	regional reliability	Upgrade Pawnee Lake - NW 68th & Holdrege line to 137 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.	$150,000,000	NPPD	04/01/10	M	NTC		Pawnee Lk 115 kV	NW 68th & Holdrege 115 kV	1
	10973	606	regional reliability	Upgrade Rising City - Seward line to 120 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.		NPPD	04/01/10	M	NTC		Rising City 115 kV	Seward 115 kV	1
	11162	606	regional reliability	Add Columbus East 345/115/13.8 kV transformer.		NPPD	10/13/09	M	NTC		Columbus East 115 kV	Columbus East 345 kV	1
	10957	720	transmission service	Upgrade line to 240 MVA for WEC2.	$6,750,000	NPPD	06/01/10	M			Geneva 115 kV	Sutton 115 kV	1
	10958	721	transmission service	Upgrade line to 240 MVA for WEC2.	$200,000	NPPD	06/01/10	M			Hastings 115 kV	Hastings City 115 kV	1

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	10960	723	transmission service	Upgrade line to 240 MVA for WEC2.	$8,437,500	NPPD	06/01/10	M			Sutton 115 kV	Whelan Energy Center 115 kV	1
	50252	30240	regional reliability	Install 9 Mvar capacitor bank at Cushing Oil 69kV bus.	$360,000	OGE		06/01/10	NTC		Cushing Oil2 69kV		
	50253	30240	regional reliability	Install 6 Mvar capacitor bank at Tiger Creek 69kV bus.	$240,000	OGE		06/01/10	NTC		Tiger Creek2 69kV		
	10787	614	Sponsored	Build 120 mile 345 kV, 3000 amp capacity line from new OG&E Woodward District EHV substation to Northwest substation		OGE	03/30/10	M			Northwest 345 kV	Woodward Distric EHV 345 kV	1
	10915	614	Sponsored	At Northwest substation, install a 3000 amp 345 kV breaker and new line terminal. Relocate Spring Creek Line to new bay. Terminate line from Tatonga. Install line relays and coordinate all relays at Northwest Substation.		OGE	03/30/10	M			Northwest 345 kV		1
	10788	614	Sponsored	Install 345/138 kV transformer.	$218,000,000	OGE	03/30/10	M			Woodward Distric EHV 345 kV	Woodward EHV 138 kV	
	10789	614	Sponsored	Build .5 miles of 138 kV and install terminal equipment .		OGE	03/30/10	M			Woodward EHV 138 kV	Woodward 138 kV	1
	10790	614	Sponsored	Build .5 miles of 138 kV and install terminal equipment .		OGE	03/30/10	M			Woodward EHV 138 kV	Woodward 138 kV	2
	10791	614	Sponsored	Tap Iodine - Woodward 138 kV.		OGE	03/30/10	M			Woodward EHV 138 kV	Iodine 138 kV	1
	11182	892	regional reliability	Install Canadian River 345 kV terminal equipment at new Canadian River substation tapping the Pittsburg-Muskogee line.	$5,500,000	OGE		06/01/10	NTC		Canadian River 345 kV		
	10391	310	zonal - sponsored	Conversion from 69kV to 161kV.	$1,416,000	OGE	06/01/10	M			Fitzhugh 161 kV	Helberg 161 kV	1
	10393	310	zonal - sponsored	Conversion from 69kV to 161kV.	$660,000	OGE	12/31/10	M			Altus 161 kV	Fitzhugh 161 kV	1
	10395	310	zonal - sponsored	Conversion from 69kV to 161kV.	$2,112,000	OGE	06/01/10	M			Little Spadra 161 kV	Igo 161 kV	1
	10397	309	zonal - sponsored	Relay upgrade.	$50,000	OGE	06/01/10	M			Park Lane 69 kV	Ahloso Tap 69 kV	1
	10398	310	zonal - sponsored	Conversion from 69kV to 161kV.	$2,973,000	OGE	10/01/10	M			Igo 161 kV	Razorback 161 kV	1
	10399	310	zonal - sponsored	Conversion from 69kV to 161kV.	$500,000	OGE	06/01/10	M			Razorback 161 kV	Short Mountain 161 kV	1
	10400	310	zonal - sponsored	Conversion from 69kV to 161kV.	$3,231,000	OGE	10/01/10	M			Short Mountain 161 kV	Branch 161 kV	1
20029	10463	354	regional reliability	Upgrade wavetrap and switches to 800 A at 3rd St. substation.	$100,000	OGE	06/01/10	06/01/10	NTC-Modify Scope	01/27/09	Muldrow 69 kV	3rd St 69 kV	1
20002	10513	395	regional reliability	Replace a wave trap, breaker, and increase CT ratio.	$347,073	OGE	06/01/10	M		02/13/08	Russett 138 kV	Russett 138 kV	1
	11001	758	zonal - sponsored	Rebuild Sub 902 - Sub 983 69 kV. The purpose of this project is to address maintenance-related issues, not to address violations of reliability criteria.	$2,500,000	OPPD	02/26/10	M			SUB 902 69 kV	SUB 983 69 kV	1
	50246	30234	regional reliability	Install 12 Mvar capacitor bank at Johnson Corner 115 kV substation.	$1,000,000	SEPC		06/01/10	NTC		Johnson Corner 115 kV		
	10336	256	regional reliability	Convert Johnson Corner - Pioneer line from 69 kV to 115 kV.	$10,650,000	SEPC	06/01/10	06/01/10	NTC		Johnson 115 kV	Pioneer 115 kV	1
	50217	30213	regional reliability	Install 50 Mvar capacitor bank at East Plant 115 kV bus configured as two blocks of 25 Mvar.	$2,025,000	SPS		06/01/10	NTC		East Plant 115 kV		
	50288	30250	zonal - sponsored	Install 1 stage of 7.2 Mvar	$288,000	SPS	06/01/10	M			Perryton Interchange 69 kV		
	50289	30251	zonal - sponsored	Install a 7.2 Mvar cap at Castro County 69 kV	$288,000	SPS	06/01/10	M			Castro County Interchange 69 kV		
	50257	30244	regional reliability	Replace 800A wave trap with 1200A.	$225,000	SPS		06/01/10	NTC		Harrington Station Mid Bus 230 kV		
	10407	315	regional reliability	Upgrade terminal equipment, Rate A & B 185 MVA	$200,000	SPS	06/01/10	M			Roosevelt County Interchange 115 kV	Curry County Interchange 115 kV	
20004	10317	248	regional reliability	Install 115/69 kV Graves transformer.		SPS	06/01/10	M		02/13/08	Grave County Tap 115 kV	Graves Sub 69 kV	
20004	10318	248	regional reliability	Install new 230/115 kV transformer at Wheeler Co (near State Line of Oklahoma and Texas)	$10,585,000	SPS	06/01/10	M		02/13/08	Wheeler Interchange 230 kV	Wheeler Interchange 115 kV	
20004	10319	248	regional reliability	Build new 17 mile Wheeler Co to Graves 115 kV and modify 69 kV bus.		SPS	06/01/10	M		02/13/08	Wheeler Interchange 115 kV	Graves Sub 115 kV	
20004	10800	248	regional reliability	Wheeler County tap	$2,000,000	SPS	06/01/10	M		02/13/08	Elk City 230KV	Wheeler Interchange 230 kV	1
20004	10801	248	regional reliability	Wheeler County tap		SPS	06/01/10	M		02/13/08	Grapevine Interchange 230 kV	Wheeler Interchange 230 kV	1
20031	10326	156	regional reliability	Build new 50 mile Moore County - Hitchland 230 kV rated at 541 MVA.	$16,094,371	SPS	12/31/10	M		01/27/09	Moore Co 230 kV	Hitchland 230 kV	1
20004	10327	156	regional reliability	Add 3-Winding 345/230 kV transformer at Hitchland - 560 MVA.	$12,577,500	SPS	06/01/10	M		02/13/08	Hitchland 345 kV	Hitchland 230 kV	1
20004	10328	156	regional reliability	Build new 28 mile Hitchland - Sherman Tap 115 kV rated at 161 MVA.	$15,848,000	SPS	06/01/10	M		02/13/08	Sherman Tap 115 kV	Hitchland 115 kV	1
20004	10329	156	regional reliability	Add 115 kV line from Sherman to Dallam - 161 MVA.	$10,771,825	SPS	06/01/10	M	NTC-Modify Scope	02/13/08	Sherman Sub 115 kV	Dallam County Interchange 115 kV	1
20004	10200	156	regional reliability	Build new 9 mile Hitchland - Texas Co. 115 kV rated at 161 MVA.	$5,132,829	SPS	06/01/10	M		02/13/08	Texas County Interchange 115 kV	Hitchland 115 kV	2
20004	10201	156	regional reliability	Add 2-winding 230/115 kV transformer at Hitchland - 252 MVA.	$31,915,701	SPS	06/01/10	M		02/13/08	Hitchland 115 kV	Hitchland 230 kV	1
20004	10802	156	regional reliability	Tap the Texas County to Hansford line.		SPS	06/01/10	M		02/13/08	Hitchland 115 kV	Hansford 3 115 kV	1
20004	10805	156	regional reliability	Tap the Texas County to Hansford line.		SPS	06/01/10	M		02/13/08	Texas County Interchange 115 kV	Hitchland 115 kV	1
20031	10704	554	regional reliability	Build new 35 mile Dallam - Channing 115 kV using 795 ACSR.		SPS	12/31/10	M		01/27/09	Dallam County Interchange 115 kV	Channing 115 kV	1
20031	10705	554	regional reliability	Convert 15 mile Channing - Tascosa line from 69 kV to 115 kV with 795 ACSR.	$27,452,677	SPS	12/31/10	M		01/27/09	Channing 115 kV	Tascosa 115 kV	1
20031	10706	554	regional reliability	Convert 30 mile Tascosa - Northwest Interchange line from 69 kV to 115 kV with 795 ACSR.		SPS	12/31/10	M		01/27/09	Tascosa 115 kV	Northwest Interchange 115 kV	1
	11018	773	regional reliability	Add 2nd 230/115 kV transformer at Roosevelt.	$5,670,000	SPS		06/01/10	NTC		Roosevelt County Interchange 115 kV	Roosevelt County Interchange 230 kV	2
	11026	776	regional reliability	Build new 1 mile Deaf Smith to Panda 115 kV line.	$600,000	SPS	06/30/10	06/01/10	NTC		Deaf Smith County Interchange 115 kV	Panda Energy Substation, Hereford 115 kV	1
	11027	777	regional reliability	Reconductor 2.24 mile East Plant - Manhattan 115 kV line.	$1,100,000	SPS		06/01/10	NTC		East Plant Interchange 115 kV	Manhattan Sub 115 kV	1
	11032	782	regional reliability	Rebuild 4 mile Osage Switching Station - South Georgia Interchange 115 kV with 795 ACSR.	$1,687,500	SPS		06/01/10	NTC		South Georgia Interchange 115 kV	Osage Switching Station 115 kV	1
	11084	821	regional reliability	Reconductor 2 mile Osage Switching Station - Randall County Interchange 115 kV line with 795 ACSR.	$1,125,000	SPS		06/01/10	NTC		Osage Switching Station 115 kV	Randall County Interchange 115 kV	1
	11097	830	regional reliability	Reconductor 1.6 mile Manhattan - Randall County Interchange 115 kV line with 795 ACSR.	$900,000	SPS		06/01/10	NTC		Manhatten Tap 115 kV	Randall County Interchange 115 kV	1
	11121	851	regional reliability	Replace existing wavetrap with 1200 A unit.	$225,000	SPS	06/16/10	06/01/10	NTC		Harrington Mid 230 kV	Randall Co 230 kV	1
	10439	342	regional reliability - non OATT	Upgrade the bus to 1200 amp and reconnect CT ratios to 1200/5.	$2,200,000	SWPA	01/01/10	06/01/10			Bull Shoals 161 kV	Bullshoals 161 kV	1
	10125	101	regional reliability - non OATT	Replace Eufaula161/138 kV transformer with 200 MVA unit.	$3,000,000	SWPA	10/01/10	M			Eufaula 161 kV	Eufaula 138 kV	1
20003	50085	30079	regional reliability	Install 12 Mvar capacitor at Carter Jct which makes at total of 24 Mvar.	$324,000	WFEC	06/01/10	M		02/13/08	Carter 69 kV		
20030	50180	30172	regional reliability	Install 12 Mvar capacitor at Eagle Chief Southwest 69 kV bus.	$300,000	WFEC	06/01/10	M		01/27/09	Eagle Chief 69 kV		
20003	10176	138	regional reliability	Upgrade WFEC Woodward sub to 1200 A and reconductor from 336.4 ACSR to 795 ACSR; new rating 91/110 MVA.	$1,050,000	WFEC	06/01/10	M		02/13/08	OGE Woodward 69 kV	WFEC Woodward 69kV	1
20030	10305	239	regional reliability	Build new 4 mile AEP Snyder - WFEC Snyder 138 kV.	$3,373,000	WFEC	12/31/10	M		01/27/09	AEP Snyder 138 kV	WFEC Snyder 138 kV	1
20003	10307	241	regional reliability	Rebuild 2 mile Anadarko - Georgia 138 kV line from 556 to 1113 ACSR.	$1,124,000	WFEC	06/01/10	M		02/13/08	Anadarko 138 kV	Georgia 138 kV	1
20003	10308	242	regional reliability	Elmore - Paoli Rebuild 3/0 to 336 ACSR - 10.8 miles.	$3,240,000	WFEC	06/01/10	M		02/13/08	Elmore 69 kV	Paola 69 kV	1
20003	10309	243	regional reliability	Convert 5 mile Oklahoma University (OU) Switch - Goldsby from 69 kV to 138 kV.	$2,753,800	WFEC	06/01/10	M		02/13/08	OU Switchyard 138 kV	Goldsby 138 kV	1
20003	10310	243	regional reliability	Convert 6 mile Goldsby - Canadian Switch from 69 kV to 138 kV.	$2,250,000	WFEC	06/01/10	M		02/13/08	Goldsby 138 kV	Canadian SW 138 kV	1
20003	10311	243	regional reliability	Install 138/69 kV transformer at Oklahoma University.	$5,000,000	WFEC	06/01/10	M		02/13/08	OU Switchyard 138 kV	OU Switchyard 69 kV	1
20003	10174	136	regional reliability	Build new 10 mile Meeker - Hammett 138 kV and install terminal equipment.	$6,674,000	WFEC	06/01/10	M		02/13/08	Meeker 138 kV	Hammett 138 kV	1
20003	10175	137	regional reliability	Reconductor 18.9 mile Wakita - Hazelton Junction 69 kV from 1/0 ACSR to 336.4 ACSR for new rating of 53/65 MVA.	$5,378,750	WFEC	06/01/10	M		02/13/08	Wakita 69 kV	Hazelton 69 kV	1
20003	10401	311	regional reliability	Convert 5 mile Acme - Franklin from 69 kV to 138 kV.	$2,065,000	WFEC	06/01/10	M		02/13/08	Franklin SW 138 kV	ACME 138 kV	1
20003	10402	311	regional reliability	Convert 4 mile West Norman - Acme from 69 kV to 138 kV.	$1,601,000	WFEC	06/01/10	M		02/13/08	ACME 138 kV	West Norman 138 kV	1
20003	10403	311	regional reliability	Convert 8 mile OU - West Norman from 69 kV to 138 kV.	$1,577,000	WFEC	06/01/10	M		02/13/08	West Norman 138 kV	OU SW 138 kV	1
20030	10794	616	regional reliability	Convert 11 mile Dover Southwest - Dover from 69 kV to 138 kV and install terminal equipment at Dover Southwest.	$5,765,600	WFEC	06/01/10	M		01/27/09	Dover SW 138 kV	Dover 138 kV	1
20030	10795	616	regional reliability	Convert 12.6 mile Dover - Twin Lakes from 69 kV to 138 kV.	$5,315,700	WFEC	06/01/10	M		01/27/09	Dover 138 kV	Twin Lakes 138 kV	1
20030	10796	616	regional reliability	Convert 7.5 mile Twin Lakes - Cashion from 69 kV to 138 kV.	$3,164,000	WFEC	06/01/10	M		01/27/09	Twin Lakes 138 kV	Cashion 138 kV	1
20030	10797	616	regional reliability	Build new 7 mile WFEC Twin Lakes - OG&E Crescent 138 kV.	$3,937,500	WFEC	06/01/10	M		01/27/09	Twin Lakes 138 kV	Crescent 138 kV	1
20030	10798	617	regional reliability	Upgrade CTs at Lake Creek (Carter Branch) to 600A.	$150,000	WFEC	06/01/10	M		01/27/09	Carter JCT 69 kV	Lake Creek 69 kV	1
20030	10799	135	regional reliability	Reconductor 3.7 miles of 1/0 ACSR to 556.5 ACSR from Lindsay to Lindsay Southwest 69 kV.	$1,248,750	WFEC	06/01/10	M		01/27/09	Lindsay 69 kV	Lindsay SW 69 kV	1
20030	10173	135	regional reliability	Reconductor 6.9 miles of 1/0 ACSR to 336.4 ACSR from Bradley to Rush Springs 69 kV.	$2,328,750	WFEC	06/01/10	M		01/27/09	Bradley 69 kV	Rush Springs 69 kV	1
19985	10179	140	regional reliability	Reconductor 3.8 miles from 3/0 ACSR to 795 ACSR. Rate A=81MVA, Rate B=106MVA	$912,000	WFEC	06/01/10	M		02/02/07	ACME 69 kV	W Norman 69 kV	1
20006	10220	171	regional reliability	Rebuild Weaver-Rose Hill 69 kV	$2,242,907	WR	12/01/10	M		02/13/08	Weaver 69 kV	Rose Hill 69 kV	1
20006	50062	30056	regional reliability	Add 10.9 Mvar capacitor bank at Trans Canada 115 kV instead of Seneca.	$588,600	WR	06/01/10	06/01/17	NTC-Modify Timing & Scope	02/13/08	Trans Canada / Seneca 115 kV		
	50290	30252	zonal - sponsored	Add 76.8 Mvar bank at Benton	$3,072,000	WR	12/01/10	M			Benton 138 kV		
19986	50088	30082	Zonal Reliability	Install switched capacitor bank.	$500,000	WR	6/1/2010	M		02/02/07	3rd & VanBuren 115 kV		
19986	50063	30057	Zonal Reliability	Install 15 Mvar capacitor at Nortonville 69 kV (bus #533481).	$715,000	WR	6/1/2010	M		02/02/07	Nortonville 69 kV		
20059	10231	182	regional reliability	Rebuild approximately 7.5 miles Chase - White Junction 69 kV line. Replace existing 2/0 copper conductor to achieve a minimum 600 amp emergency rating.	$5,184,701	WR	06/01/10	M		09/18/09	Chase 69 kV	White Junction 69 kV	1
19964	10412	318	transmission service	AEP - Tie Line, Reconductor 1.09 miles of 795 ACSR with 1590 ACSR. WERE - Tie Line, Rebuild 3.93 miles of 795 ACSR with 1590 ACSR. AEP: The limiting factor is the AEP portion of 795 ACSR conductor The estimated cost of doing a sag analysis on this line to see if it can rated for a higher limit is 6000 New ratings are for AEP only. The new limit is the 1590 ACSR conductor Per MW-Mile files, 78% WR, 22% AEP of 5.02 miles	$2,819,000	WR	06/01/10	M		06/27/07	Coffeyville Tap 138 kV	Dearing 138 kV	1
	10345	262	Sponsored	Install new 50.55-mile 345 kV line from Reno county to Summit; 31 miles of 115 kV line between Circle and S Philips would be rebuilt as double circuit with the 345 kV line to minimize ROW impacts; Substation work required at Summit for new 345 kV terminal and completion of ring bus.	$100,618,016	WR	06/01/10	M			Reno County 7 345 kV	Summit 345 kV	1
20006	10426	330	regional reliability	Tap Litchfield-Marmaton 161 kV with new SWBourb5 bus to Ft Scott	$5,000,000	WR		M		02/13/08	Southwest Bourbon 161 kV	Fort Scott 161 kV	1
20006	10424	328	regional reliability	Rebuild Circle - Moundridge 115 kV	$5,800,000	WR	06/01/10	M		02/13/08	Circle 115 kV	Moundridge 115 kV	1

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	10425	328	zonal - sponsored	Install New (2nd) 138/115 kV transformer at Moundridge (57429/57013). Operate both 138/115 kV transformers normally closed.	$1,700,000	WR	06/01/10				Moundridge 138 kV	Moundridge 115 kV	2
20006	10219	170	regional reliability	3.53 miles Anzio - Fort Junction Switching Station 115 kV	$3,639,327	WR	06/01/10	M		02/13/08	Anzio 115 kV	Fort Junction	1
20033	10809	621	regional reliability	Uprate JEC- E. Manhattan 230 kV line to 100 deg C operation by raising structures.	$17,085,938	WR		M		01/27/09	E. Manhattan 230 kV	JEC 230 kV	1
20033	10813	625	regional reliability	Rebuild the 2.37 mile Chisholm - Ripley 69 kV line using single 1192.5 ACSR.	$2,255,250	WR	06/01/10	M		01/27/09	Chisholm 69 kV	Ripley 69 kV	1
20019	10739	578	regional reliability	New 115 kV Line from Knob Hill to Kansas/Nebraska state line.	$25,751,000	WR	06/01/10	M		11/17/08	Knob Hill 115 kV	Steele City 115 kV	1
20019	10738	577	regional reliability	Rebuild 10.3 mile line between Kelly and South Seneca.	$5,825,000	WR	12/01/10	M		11/17/08	Kelly 115 kV	South Seneca 115 kV	1
20033	10766	599	regional reliability	Tear down and rebuild the 2.72 mile Tecumseh Hill - 27th & Croco 115 kV line as a single circuit.	$3,890,000	WR	12/31/10	M		01/27/09	Tecumseh Hill 115 kV	27th & Croco 115 kV	1
20059	50235	30228	transmission service	Replace Jumpers to achieve a minimum 600 amp emergency rating.	$115,000	WR	06/01/10			09/18/09	Tioga 69 kV	Chanute TAP 69 kV	1
20059	50237	30229	transmission service	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers with a minimum 2000 amp emergency rating equipment	$600,000	WR	06/01/10			09/18/09	Coffeyville Tap 138 kV	Dearing 138 kV	1
20059	50238	30224	transmission service	Rebuild approximately 7 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.	$3,335,500	WR	07/01/10			09/18/09	Green 69 kV	Coffey County No. 4 Vernon 69 kV	1
20059	10711	561	transmission service	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers a minimum 2000 amp emergency rating	$5,513,000	WR	06/01/10	M		09/18/09	Evans Energy Center South 138 KV	Lakeridge 138 KV	1
						Year 2011							
	10367	283	Inter-regional	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Chouteau 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Chouteau 345kV bus a 345/161 transformer connects to Chouteau 161kV sub.		AECI	06/01/12				Blackberry 345 kV	Sportsman Acres 345	1
	10368	283	Inter-regional	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.		AECI	02/01/11				Sportsman Acres 345	GRDA 1 345 kV	1
	10369	283	Inter-regional	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.	$57,000,000	AECI	02/01/11				Sportsman Acres 345 kV	Sportsman Acres 161 kV	1
	10916	283	Inter-regional	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.		AECI	02/01/11				Sportsman Acres 345 kV	Sportsman Acres 161 kV	2
	10781	283	Inter-regional	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.		AECI	02/01/11				Sportsman Acres 161kV	Chouteau 161 kV	
	10459	350	Generation Interconnect	Replace breaker 3310.	$277,000	AEP	12/31/11				Bann 138 kV	Red Springs REC 138 kV	1
	10446	349	Generation Interconnect	Reconductor and convert line to 138 kV and replace switches at Ashdown REC	$7,810,000	AEP	06/01/11	M			Ashdown REC (Millwood) 138 kV	Okay 138 kV	1
	10447	349	Generation Interconnect	Reconductor line and convert line to 138 kV. Convert Patterson station to breaker-and-a half configuration.	$11,431,000	AEP	12/31/11	M			Ashdown REC (Millwood) 138 kV	Patterson 138 kV	1
	10448	349	Generation Interconnect	Build new McNab-Turk 115 kV line	$1,773,000	AEP	12/31/11	M			McNab REC 115 kV	Turk 115 kV	1
	10451	349	Generation Interconnect	Convert 115-69 kV station to 138-69 kV.	$3,266,000	AEP	12/31/11	M			Okay 69 kV	Okay 138 kV	1
	10452	349	Generation Interconnect	Build two mile, 138 kV, 1590ACSR line section from Turk Sub to existing Okay-Hope 115 kV line and rebuild twelve miles of 115 kV line to Okay Sub to 138 kV, 1590 ACSR , to form a Turk-Okay 138 kV line	$8,170,000	AEP	12/31/11	M			Okay 138 kV	Turk 138 kV	1
	10457	349	Generation Interconnect	Build Turk 138-115 kV station and relocate autotransformer (and spare) from Patterson to this new Turk station.	$7,806,000	AEP	12/31/11	M			Turk 115 kV	Turk 138 kV	1
20027	10586	452	regional reliability	Replace one breaker and four switches.	$350,000	AEP	06/01/11	M		01/27/09	Whitney 138 kV	Whitney 69 kV	1 & 2
20016	10449	349	transmission service	Reconductor about 0.5 miles of 666 ACSR with 1590 ACSR	$540,000	AEP	12/31/11	M		01/16/09	McNab REC 115 kV	Turk 115 kV	1
20016	10450	349	transmission service	Reconductor 3.55 miles of 666 ACSR with 1590 ACSR	$2,170,000	AEP	12/31/11	M		01/16/09	McNab REC 115 kV	Hope 115 kV	1
20048	10578	446	transmission service	Rebuild approximately 13 miles of line with 1590 ACSR to achieve a minimum 2000 Amp emergency rating	$13,100,000	AEP	06/01/11			09/18/09	North Bartlesville 138 kV	Coffeyville Tap 138 kV	1
20048	10588	454	transmission service	Rebuild approximately 8.5 miles of line with 1590 ACS to achieve a minimum 2000 Amp emergency rating & reset relays at Bartlesville Southeast accordingly	$8,400,000	AEP	06/01/11			09/18/09	Bartlesville Southeast 138 kV	North Bartlesville 138 kV	1
	10373	287	zonal - sponsored	Build 12 miles of 138 kV from Etoile - Chireno	$11,299,000	DETEC	06/01/11				Etoile 138 kV	Chireno 138 kV	1
19970	10644	499	transmission service	Replace Auto transformer at ORONOGO 110 with 150 MVA rated Auto transformer due to increased generation available	$4,000,000	EDE	06/01/11	M		01/10/08	ORO110 5 161 IV	ORO110 2 69 kV	1
19970	10730	352	transmission service	Reconductor 11.9 miles of Oronogo Jct. to Riverton 161kV Ckt. 1 from 556 ACSR to 795 ACSR, change CT settings @ Oronogo, and replace wavetrap.	$5,750,000	EDE	06/01/11	M		01/10/08	Sub 110 - Oronogo Jct.	Sub 167 - Riverton	1
	10370	284	Inter-regional	Entergy Planning has identified this proposed project as installing a new switching station, Grandview, on the existing 161 kV line between Table Rock Dam and Eureka Springs substation and constructing a new 161 kV line between Grandview and the existing Osage Creek substation.	$6,000,000	EES	06/01/11	06/01/10			Grandview 161 kV	Osage 161 kV	1
20034	10830	634	regional reliability	Tap the Montrose - LomaVista 161 kV Line into KC South 161 kV substation. This project is an alternative to replace the reconductor project of the Duncan Rd - Blue Spring East and Martin City - Grandview East 161 kV lines.	$2,369,625	GMO	11/01/11	M		01/27/09	Loma Vista 161 kV	KC South 161 kV	1
	10431	334	zonal - sponsored	Radial Line From Greenwood to a new distribution sub at Lone Jack	$7,096,402	GMO	06/01/11	M			Lone Jack 161 kV	Greenwood 161 kV	1
	10428	331	zonal - sponsored	Tap Clinton AECI (300071) to Clinton MIPU (541242) with new Clinton bus and tie in existing Clinton transformer into new bus.	$2,418,750	GMO	06/01/11				Clinton 161 kV		
20034	10854	650	regional reliability	Tap Stilwell - Archie Junction 161 kV line into South Harper 161 kV sub and make it two new 161 kV sections: Stilwell - South Harper and Archie Junction - South Harper.	$2,259,673	GMO	06/01/11	M		01/27/09	Stilwell 161 kV	Archie 161 kV	1
	50194	30187	regional reliability	Add 20 Mvar capacitor bank at Adrian 161 kV.	$810,000	GMO		06/01/11	NTC		Adrian 161kV		
20053	50224	30220	regional reliability	Add 50 Mvar cap bank at Blue Springs East	$1,400,000	GMO	06/01/11			09/18/09	Blue Springs East 161 kV		
	10361	278	zonal - sponsored	161kV Tap of Longview to Grandview East	$893,868	GMO	06/01/11	M			Longview 161 kV	Sampson 161 kV	1
	10362	278	zonal - sponsored	161kV Tap of Longview to Grandview East	$0	GMO	06/01/11	M			Sampson 161 kV	Grandview East 161 kV	1
	10356	273	zonal - sponsored	161kV Tap of Nashua to Liberty West	$1,350,000	GMO	06/01/11	M			Cookingham 161 kV	Liberty West 161 kV	1
	10357	273	zonal - sponsored	161kV Tap of Nashua to Liberty West		GMO	06/01/11	M			Nashua 161 kV	Cookingham 161 kV	1
20056	50227	30223	transmission service	Reconductor the line from 1192 ACSR to 1192 ACSS and rebuild the line terminals to 2000 amp capability	$4,400,000	GMO	06/01/11			09/18/09	ST Joe 161 KV	Cook 161 KV	1
20001	50092	30086	regional reliability	Install 21.8 Mvar capacitor at Jay 69 kV substation.	$800,000	GRDA	06/01/11	M		02/13/08	Jay Gr2 69 kV		
20001	10511	393	regional reliability	Add 50MVA 161/69 kV transformer #2 at Afton.	$2,500,000	GRDA	06/01/11	06/01/10	NTC-Modify Timing	02/13/08	Afton161 kV	Afton 69 kV	1
	10390	302	zonal - sponsored	Tap the GRDA 1-Flint Creek 345 kV line and build a 345/161 transformer. Then build a 161 kV line down to Siloam Springs.	$8,019,000	GRDA	12/01/11	M			Siloam Springs Tap 345 kV	Siloam Springs Tap 161 kV	1
20050	10512	394	regional reliability	Rebuild approximately 22 miles of line with 795 ACSR	$10,450,000	GRDA	06/01/11			09/18/09	Kerr 161 kV	Pensacola 115 kV	1
20051	50221	30217	transmission service	Add 20 Mvar cap bank to make a total of 70 Mvar at Craig 161kV	$50,000	KCPL	06/01/11			09/18/09	Craig 161 kV		
20051	50222	30218	transmission service	Reconductor line and upgrade terminal equipment for 2000 amps	$2,200,000	KCPL	06/01/11			09/18/09	Stilwell 161 kV	Redel 161 kV	1
20032	50184	30176	regional reliability	Install 5 Mvar Cap at Kinsley 115 kV.	$300,000	MIDW	06/01/11	06/01/11	NTC-Modify Scope	01/27/09	Kinsley 115 kV		
	50197	30190	regional reliability	Install 5 Mvar capacitor bank at Pawnee 115 kV.	$300,000	MIDW		06/01/11	NTC		Pawnee 115 kV		
20007	50096	30090	regional reliability	Add 9.6 Mvar capacitor at Russell 115 kV.	$1,300,000	MKEC	06/01/11	M		02/13/08	Russell 115 kV		
	50211	30204	regional reliability	Install 10.8 Mvar capacitor bank at Valentine 115 kV.	$1,000,000	NPPD	06/01/11	06/01/11	NTC		Valentine 115 kV		
	10924	609	regional reliability	Build new 161-kV substation Sub 1341. Remove 0.06 mile of 161 kV line from Sub 1251- Sub 1305.		OPPD	12/31/11	M	NTC		SUB 1341 161 kV		
	10925	609	regional reliability	Tap 161-kV line from Sub 1251 to Sub 1305 and route it into and out of new 161-kV substation Sub 1341.	$16,300,000	OPPD	12/31/11	M	NTC		SUB 1341 161 kV	SUB 1251 161 kV	1
	10926	609	regional reliability	Tap 161-kV line from Sub 1251 to Sub 1305 and route it into and out of new 161-kV substation Sub 1341.		OPPD	12/31/11	M	NTC		SUB 1341 161 kV	SUB 1305 161 kV	1
	50148	304	zonal - sponsored	Add 9 Mvar of emergency capacitors	$264,000	OGE	03/01/11				Macili Industries 138 kV		
	10392	310	zonal - sponsored	Conversion from 69kV to 161kV	$543,000	OGE	03/31/11	M			Great Lakes Carbon 161 kV	Altus 161 kV	1
	10394	310	zonal - sponsored	Conversion from 69kV to 161kV	$2,994,000	OGE	03/31/11	M			Igo 161 kV	Noark 161 kV	1
	10396	310	zonal - sponsored	Conversion from 69kV to 161kV	$522,000	OGE	03/31/11	M			Noark 161 kV	Great Lakes Carbon 161 kV	1
	11190	895	zonal - sponsored	Three terminal line will be upgraded to 2000A with breakers. Limiting equipment will be 795AS33 conductor.	$1,300,000	OGE	04/01/11	M			Stonewall138 kV	Remington Park 138 kV	1
20017	50166	30158	transmission service	Replace 4.65 miles of line with 477AS33	$1,400,000	OGE	06/01/11	M		01/16/09	Rocky Point 69 kV	Ardmore 69 kV	1
20017	50170	30162	transmission service	Replace wavetrap 800A at Uniroyal	$50,000	OGE	06/01/11	M		01/16/09	Sunnyside 138 kV	Uniroyal 138 kV	1
20017	50167	30159	transmission service	Replace Differential Relaying	$300,000	OGE	06/01/11	M		01/16/09	Dillard 138 kV	Healdton Tap 138 kV	1

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20029	10792 & 10793	615	regional reliability	Convert 13.64 miles of 69 kV to 138 kV from Crescent to Cottonwood Creek and install terminal equipment at Cottonwood Creek, completing loop from Crescent to Twin Lakes (WFEC).	$5,404,250	OGE	06/01/11	M		01/27/09	Crescent 138 kV	Cottonwood Creek 138 kV	1
	11188	896	zonal - sponsored	Bell Cow Sub is delayed until 2011. Install Bell Cow sub and associated lines, remove chandler sub.		OGE	05/30/11	M			Keystone West 138 kV	Bell Cow 138 kV	1
	11189	896	zonal - sponsored	Bell Cow Sub is delayed until 2011. Install Bell Cow sub and associated lines, remove chandler sub.		OGE	05/30/11	M			Warwick 138 kV	Bell Cow 138 kV	1
	10731	304	zonal - sponsored	At Caney Creek remove 2 existing line terminals to the north and expand the 138 kV bus north into a ring bus		OGE	06/01/11	M			Caney Creek 138 kV		1
	10732	304	zonal - sponsored	Construct 25 miles of 138 kV of 795AS33 line from the new Johnson County sub to Caney Creek.		OGE	06/01/11	M			Johnson County 138 kV	Caney Creek 138 kV	1
	10733	304	zonal - sponsored	Build a new 345 EHV substation in the Sunnyside to Pittsburg line. Install a 400 MVA transformer with 3-345kv breakers in a ring bus and 4-138kv breakers in a ring bus at new Johnson County sub.		OGE	06/01/11	M			Johnson County 345 kV	Johnson County 138 kV	1
	10734	304	zonal - sponsored	Replace relays at Sunnyside 345 kV	$32,975,000	OGE	06/01/11	M			Sunnyside 345 kV	Johnson County 345 kV	1
	10735	304	zonal - sponsored	Replace relays at Pittsburg 345 kV		OGE	06/01/11	M			Johnson County 345 kV	Pittsburg 345 kV	1
	10820	304	zonal - sponsored	Tap the MillCreek to Russett 138 kV into the New Johnson County substation		OGE	06/01/13	M			Johnson County 138 kV	Millcreek	1
	10821	304	zonal - sponsored	Tap the MillCreek to Russett 138 kV into the New Johnson County substation and reconductor Jonson County to Russett Sub with 795 AS33		OGE	06/01/13	M			Johnson County 138 kV	Russett 138 kV 138 kV	1
	10747	582	zonal - sponsored	Install Terminal equipment to remove Three terminal line	$1,900,000	OGE	06/01/11	M			Cottonwood Creek 138 kV	Arcadia 138 kV	1
	10748	582	zonal - sponsored	Install Terminal equipment to remove Three terminal line		OGE	06/01/11	M			Arcadia 138 kV	Garber 138 kV	1
20041	10946	709	Balanced Portfolio	Tap Lawton East Side to Cimarron 345 kV line at Anadarko and build substation. Install a 345/138 kV transformer in substation.	$15,000,000	OGE	12/31/11	M		06/19/09	Anadarko (Gracemont) 345 kV	Gracemont 138 kV	1
20002	10514	396	regional reliability	Install a 138 kV breaker at Bodie to close the normally open switch. Breaker connects 515155 Bodie 138 kV to 515156 Bodie138 kV.	$1,000,000	OGE	10/01/11	M		02/13/08	Bodie 138 kV	Bodie 138 kV	1
	50247	30235	regional reliability	Install 2nd 115 kV 12 Mvar cap bank at Johnson Corner substation.	$650,000	SEPC		06/01/11	NTC		Johnson Corner 115 kV		
	10214	165	zonal - sponsored	Build new 35 mile Phillipsburg - Rhoades 115 kV.	$10,500,000	SEPC	09/01/11	M			Phillipsburg 115 kV	Rhoades 115 kV	1
20007	10215	166	regional reliability	Rebuild 12 mile Holcomb - Plymell 115 kV.	$3,650,000	SEPC	09/01/11	M		02/13/08	Holcomb 115 kV	Plymell 115 kV	1
20014	10480	367	regional reliability	Rebuild 15 mile Holcomb - Pioneer Tap 115kV.	$3,200,000	SEPC	09/01/11	M		09/18/08	Plymell 115 kV	Pioneer Tap 115 kV	1
	50259	30246	regional reliability	Install 2 Blocks of 7.2 Mvar capacitor bank at Kress 69 kV.	$583,200	SPS		06/01/11	NTC		Kress Rural 69 kV		
	11040	791	regional reliability	Tap the Potter Interchange - Plant X Station 230 kV line for new Newhart Substation install 230/115 kV 150/173 MVA transformer.	$11,250,000	SPS	12/22/11	06/01/10	NTC		Newhart 230 kV	Newhart 115 kV	1
	11090	824	regional reliability	New 345/230 kV transformer rated 515/560 MVA at Hobbs Interchange.	$11,250,000	SPS	12/22/11	06/01/10	NTC		Hobbs Interchange 230 kV	Hobbs Interchange 345 kV	1
	11091	824	regional reliability	New 345/138 kV transformer rated 400/440 MVA at Midland.	$11,250,000	SPS	12/22/11	06/01/10	NTC		Midland 345 kV	Midland 138 kV	1
	11029	779	regional reliability	Reconductor 6.15 mile Maddox - Sanger Switching Station 115kV line for 226/239 MVA rating.	$3,000,000	SPS	06/25/11	06/01/10	NTC		Maddox Station 115 kV	Sanger Switching Station 115 kV	1
	11019	774	regional reliability	New Tap to new Cherry 230/115 kV Transformer.	$112,500	SPS	08/24/11	06/01/10	NTC		Cherry Sub 230 kV	Potter County Interchange 230 kV	1
	11020	774	regional reliability	New 230/115 kV Autotransformer at Cherry Substation.	$4,905,000	SPS	08/24/11	06/01/10	NTC		Cherry Sub 230 kV	Cherry Sub 115 kV	1
20031	10757	590	regional reliability	Convert 8 miles of 69 kV to 115 kV from Carlsbad Interchange - Ocotillo. Convert Ocotillo substation to 115 kV.	$1,222,843	SPS	06/01/11	06/01/10		01/27/09	Carlsbad Interchange 115 kV	Ocotillo Sub 115 kV	1
20004	10325	156	zonal - sponsored	Add 230 kV line from Pringle to Hitchland - 541 MVA.	$11,922,643	SPS	06/01/11	M		02/13/08	Pringle Interchange 230 kV	Hitchland 230 kV	1
20004	10330	156	regional reliability	Add 230 kV line from Hitchland to Ochiltree - 541 MVA.	$10,766,250	SPS	06/01/11	M		02/13/08	Hitchland 230 kV	Ochiltree 230 kV	1
20004	10331	156	regional reliability	Add 2-Winding 230/115 kV transformer at Ochiltree – 172.5 MVA	$5,846,295	SPS	06/01/11	M		02/13/08	Perryton Interchange 115 kV	Ochiltree 230 kV	1
	11033	783	regional reliability	Install second 230/115 kV transformer in Randall substation.	$11,250,000	SPS	08/24/11	06/01/10	NTC		Randall County Interchange 230 kV	Randall County Interchange 115 kV	2
20031	10822	632	regional reliability	Tap line from Tenneco - Boardman Tap 69 kV and add new 75/75 MVA 115/69 kV transformer at new Legacy Interchange substation.	$3,937,500	SPS	06/01/11	M		01/27/09	Legacy Interchange 115 kV (new Interchange a	Boardman Tap 69 kV	1
20031	10823	632	regional reliability	Build new 6 mile 115 kV line from Doss Interchange - Legacy Interchange.	$3,375,000	SPS	06/01/11	M		01/27/09	Doss Interchange 115 kV	Legacy Interchange 115 kV (new Interchange and sub)	1
20031	10824	632	regional reliability	Build new 5.5 mile 115 kV line from Gaines County Interchange - Legacy Interchange.	$3,093,750	SPS	06/01/11	M		01/27/09	Gaines County Interchange 115 kV	Legacy Interchange 115 kV (new Interchange and sub)	1
20031	10825	633	regional reliability	Tap line 69 kV from Navajo No. 2 - Navajo No. 4, tap line 115 kV from Navajo No. 3 - Navajo No. 4, and install Eagle Creek Substation and 115/69 kV transformer.	$3,285,000	SPS	04/15/11	M		01/27/09	Eagle Creek 69 kV (new sub)	Eagle Creek 115 kV (new sub)	1
20031	10826	633	regional reliability	Build new 0.5 mile 115 kV line from new Navajo No. 5 substation - Navajo No. 4 substation 115 kV.	$281,250	SPS	04/15/11	M		01/27/09	Navajo No.5 Sub 115 kV (new sub)	Navajo No.4 Sub 115 kV	1
20031	10827	633	regional reliability	Build new 0.5 mile 115 kV line from new Navajo No. 5 substation - Navajo No. 3 substation 115 kV.	$281,250	SPS	04/15/11	M		01/27/09	Navajo No.5 Sub 115 kV (new sub)	Navajo No.3 Sub 115 kV	1
20031	10828	633	regional reliability	Build new 3 mile 69 kV line from Artesia Town - Artesia South Rural 69 kV.	$1,350,000	SPS	04/15/11	M		01/27/09	Artesia Town Sub 69 kV	Artesia South Rural Sub 69 kV	1
20031	10829	696	regional reliability	Convert 11.8 miles of 69 kV line to 115 kV from Chaves County - Price - Central Valley REC-Pine Lodge - Capitan - Roswell. SPS-provided mitigation was verified by SPP staff until 12/2012 when the conversion will be completed.	$4,716,600	SPS	06/01/11	06/01/11		01/27/09	Chaves County Interchange 115 kV	Roswell Interchange 115 kV	1
	11036	786	regional reliability	Reconductor 3.36 mile Maddox - Monument CKT 1 115 kV with 795 ACSR.	$1,417,500	SPS	06/25/11	06/01/11	NTC		Maddox Station 115 kV	Monument Sub 115 kV	1
	11096	829	regional reliability	Install second 115/69 kV transformer rated 75/86 MVA at Kingsmill.	$1,935,000	SPS	12/22/11	06/01/11	NTC		Kingsmill 69 kV	Kingsmill 115 kV	2
19987	10194	150	regional reliability	Upgrade #2 Transformer	$1,250,000	SPS	-	06/01/11		02/02/07	Kress 69 kV	Kress 115 kV	2
	11196	857	regional reliability	Reconductor EAST PLANT-PIERCE 1.06 miles 115 kV to 795 ACSR line	$596,250	SPS		06/01/11	NTC		East Plant 115 kV	Pierce 115 kV	1
	10741	580	regional reliability - non OATT	Replace Paragould auto transformers 1 and 2 with 70 MVA units.	$3,150,000	SWPA		12/01/11			Paragould 161 kV	Paragould 69 kV	1 & 2
	10944	612	regional reliability - non OATT	Replace wave trap, disconnect switches, current transformers, and breaker at Dardanelle	$165,000	SWPA	06/01/11	06/01/10			Dardanelle 161 kV	Russellville South 161 kV	1
20044	10938	705	Balanced Portfolio	Tap the existing WFEC Anadarko - Washita 138 kV line into the new Gracemont 345 kV substation.	$200,000	WFEC	12/31/11	M		06/19/09	Anadarko (Gracemont) Tap 138 kV		1
19951	10467	357	transmission service	Install 2nd 112 MVA auto in parallel with existing Unit	$2,000,000	WFEC	06/01/11	M		01/02/07	Anadarko 138 kV	Anadarko 69 kV	2
20003	10471	361	regional reliability	Upgrade 7 miles to 795 ACSR from Fletcher SW to Marlow Junction 69 kV.	$2,000,000	WFEC	06/01/11	M		02/13/08	Fletcher 69 kV	Marlow Jct 69 kV	1
	11114	845	regional reliability	Upgrade Snyder CTs from 400A to 600A.	$225,000	WFEC		06/01/11	NTC		Snyder 69 kV	Tipton 69 kV	1
20003	10303	238	regional reliability	WFEC will build a double circuit 138 kV line, approximately 6.5 miles long, from AEP's Atoka substation to the south and looping into the WFEC Tupelo-Lane 138 kV line - Atoka to Tupelo line.	$8,265,000	WFEC	01/01/11	M		02/13/08	Atoka West 138 kV	Tupelo (WFEC) 138 kV	1
20003	10304	238	regional reliability	WFEC will build a double circuit 138 kV line, approximately 6.5 miles long, from AEP's Atoka substation to the south and looping into the WFEC Tupelo-Lane 138 kV line - Atoka to Lane line.		WFEC	01/01/11	M		02/13/08	Atoka East 138 kV	Lane (WFEC) 138 kV	1
20059	50243	30232	transmission service	Add 138 kV 30 Mvar Cap bank at Timber	$1,215,000	WR	06/01/11			09/18/09	Timber 138 kV		
20059	50244	30233	transmission service	Add 69 kV 15 Mvar Cap bank at Tioga	$607,500	WR	06/01/11			09/18/09	Tioga 69 kV		
	50291	30253	zonal - sponsored	one stage of 9.6 Mvar	$384,000	WR	06/01/11	M			Riley 115 kV		
	50292	30254	zonal - sponsored	Install 2nd block of 76.8 Mvar	$3,072,000	WR	12/01/11	M			Rose Hill 138 kV		
	50293	30255	zonal - sponsored	one stage of 10.8 Mvar	$432,000	WR	06/01/11	M			Butler County No. 5-Furley 69 kV		
20033	10349	266	regional reliability	Rebuild 0.23 mile Circle - HEC GT 115 kV line.	$710,000	WR	06/01/11	M		01/27/09	Hutchinson Gas Turbine Station 115 kV	Circle 115 kV	1
20033	10636	491	regional reliability	Rebuild 2.9 mile Bismark - Farmer's Consumer Co-op 115 kV.	$2,085,000	WR	06/01/11	06/01/11	NTC-Modify Timing	01/27/09	Bismark 115 kV	Farmer's Consumer Co-op 115 kV	1
20006	10482	369	regional reliability	Rebuild SW Lawrence - Wakarusa 115 kV line.	$2,000,000	WR	06/01/11	M		02/13/08	SW Lawrence 115 kV	Wakarusa 115 kV	1
20006	10483	370	regional reliability	Rebuild 1.53 miles Co-op-Wakarusa 115 kV line	$760,000	WR	06/01/11	M		02/13/08	Farmer's Consumer Co-op 115 kV	Wakarusa 115 kV	1
	10866	660	regional reliability	Tear down and rebuild 7.86 mile Gill - Clearwater 138 kV.	$3,324,375	WR		06/01/11	NTC		Gill W4 138 kV	Clearwater 138 kV	1
20033	10638	493	regional reliability	Rebuild Jarbalo - Stranger Ckt 2 7.1 miles of 115 kV and tap the existing Jarbalo - Northwest Leavenworth line into Stranger.	$8,050,000	WR	06/01/11	M		01/27/09	Jarbalo 115 kV	Stranger Creek 115	2
20033	10639	493	regional reliability	Rebuild Stranger - Northwest Leavenworth 6.5 miles of 115 kV and tap existing Jarbalo - Northwest Leavenworth line into Stranger.		WR	06/01/11	M		01/27/09	Stranger Creek 115	NW Leavenworth	1
20033	10606	618	regional reliability	Tap KSU - Wildcat 115 kV into Northwest Manhattan.	$17,437,500	WR	12/01/11	M		01/27/09	KSU Campus 115 KV	Wildcat 115 kV	1
20033	10608	618	regional reliability	Tap the Concordia - East Manhattan 230 kV line and build new Northwest Manhattan 230/115 kV substation.	$11,250,000	WR		M		01/27/09	Concordia 230 kV	East Manhattan 230 kV	1
20059	50239	30224	transmission service	Rebuild approximately 8.5 miles of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating.	$3,811,500	WR	12/01/11	06/01/11		09/18/09	Lehigh Tap 69 kV	Owl Creek 69 KV	1
20059	50232	30224	transmission service	Rebuild approximately 3 miles of line with 954 kcmil ACSR to achieve a minimum 600 amp emergency rating.	$1,418,500	WR	04/01/11			09/18/09	Athens Switching Station 69 kV	Owl Creek 69 KV	1
20059	50241	30230	transmission service	Replace bus and Jumpers at NE Parsons 138 kV substation	$250,000	WR	06/01/11			09/18/09	Neosho 138 kV	Northeast Parsons 138 kV	1
20059	50242	30231	Zonal Reliability	Tap Belle Plaine-Oxford 138 kV line, build a 3-breaker ring bus switching station, build approximately 12 miles 138 kV line from Sumner County 138 kV to Timber Junction 138 kV, and install Timber Junction. 138-69 kV 100 MVA transformer with LTC.	$9,360,000	WR	06/01/11			09/18/09	Timber Junction 138 kV	Summer County Tap 138 KV	1
20059	50245	30224	transmission service	Rebuild approximately 5 miles of line with 954-KCM ACSR to achieve a minimum 1200 amp emergency rating.	$2,426,500	WR	01/01/11			09/18/09	Coffey County No. 4 Vernon 69 kV	Athens Switching Station 69 kV	1
20059	10810	622	Zonal Reliability	Rebuild approximately 5.5 mile Rose Hill Junction-Richland	$2,815,000	WR	06/01/11			09/18/09	Roshe Hill Junction 69 kV	Richland 69 kV	1
20033	10767	600	regional reliability	Tear down and rebuild the 3.43 mile 27th & Croco - 41st & California 115 kV line as a single circuit.	$3,227,500	WR	12/31/11	M		01/27/09	27TH & Croco Junction 115 KV	41ST & California 115 KV	1
20006	10417	321	regional reliability	Tear down/rebuild 1.91-miles of Oaklawn - Oliver 69 kV line replacing 477 kcmil ACSR conductor with 954 kcmil ACSR conductor. Limit would be 0.2-mile 750 kcmil CU underground cable.	$1,292,500	WR	06/01/11	M		02/13/08	Oaklawn 69 kV	Oliver 69 kV	1
20033	10350	267	regional reliability	Tear down and rebuild 7.3-mile Halstead - Mud Creek 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil ACSR conductor and replace terminal equipment at substations.	$2,500,000	WR	06/01/11	06/01/11	NTC-Modify Timing	01/27/09	Halstead 69 kV	Mud Creek Junction 69 kV	1
20033	10351	267	regional reliability	Rebuild 1.0 mile Mud Creek Junction - Mid-American Junction 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil	$360,000	WR	06/01/11	06/01/11	NTC-Modify Timing	01/27/09	Mud Creek Junction 69 kV	Mid-American Junction 69 kV	1

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20033	10352	267	regional reliability	Rebuild 3.9 mile Mid-American Junction - Newton 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil ACSR conductor and replace terminal equipment at substations.	$1,300,000	WR	06/01/11	06/01/11	NTC-Modify Timing	01/27/09	Mid-American Junction 69 kV	Newton 69 kV	1
						Year 2012							
20015	50151	30143	transmission service	Upgrades to McNab Substation	$165,000	AECC	04/01/12			01/16/09	Turk 115	McNab REC 115 kV	1
20015	10460	351	transmission service	Reconductor line to 1590 ACSR the Hope-Fulton line. Build at 138 and operate at 115 kV	$1,512,000	AECC	04/01/12	M		01/16/09	Fulton 115 kV	Hope 115 kV	1
20015	10461	351	transmission service	Upgrade Fulton Switching Station	$440,000	AECC	04/01/12	M		01/16/09	Fulton 115 kV		
	50076	30070	zonal - sponsored	Add tap and switches for new delivery point along 69 kV line from 507187 Midland to old 507185 Excelsior station site.	$500,000	AEP	12/1/2012				Sugar Loaf 69 kV		
20016	50165	30157	transmission service	Rebuild 5.92 miles of 266 ACSR with 795 ACSR. Replace 69 kV switches, jumpers, and reset CTs and relays at Texarkana Plant.	$8,193,000	AEP	04/01/12	M		01/16/09	Texarkana Plant 69 kV	South Texarkana REC 69 kV	1
20016	50164	30156	transmission service	Change out the 500 Cu jumpers at Texarkana Plant.	$128,000	AEP	04/01/12	M		01/16/09	SE Texarkana 69 kV	Texarkana Plant 69 kV	1
20016	50163	30155	transmission service	Replace 69 kV switches.	$80,000	AEP	04/01/12	M		01/16/09	Okay 69 kV	Tollette 69 kV	1
20048	50156	30148	transmission service	Replace 69 kV switch at Lone Star Ordinance Tap with a minimum 800 amp emergency rating	$273,400	AEP	06/01/12	M		09/18/09	Bann 69 kV	Lone Star Ordinance Tap 69 kV	1
20016	50160	30152	transmission service	Replace 138 kV breaker, switches, and jumpers at Linwood. Replace circuit switcher at Powell Street.	$456,000	AEP	06/01/12	M		01/16/09	Powell Street 138 kV	Linwood 138 kV	1
20016	50148	30142	transmission service	Build approximately 33 miles of of 2-954 ACSR from Turk to NW Texarkana.		AEP	04/01/12	M		01/16/09	Turk 345 kV	NW Texarkana 345 kV	1
20016	50149	30142	transmission service	Add 345 kV terminal at NW Texarkana	$48,580,000	AEP	04/01/12	M		01/16/09	Turk 345 kV	NW Texarkana 345 kV	1
20016	50150	30142	transmission service	Add 345 kV terminal at Turk (Hempstead)		AEP	04/01/12	M		01/16/09	Turk 345 kV	NW Texarkana 345 kV	1
20016-1	10456	349	transmission service	Add Turk 345/138 kV transformer	$7,310,000	AEP	04/01/12	M		09/18/09	Turk 138 kV	Turk 345 kV	1
20016	10374	288	transmission service	Install 345 kV terminal equipment at Valliant Substation	$3,840,000	AEP	04/01/12	M		01/16/09	Hugo Power Plant 345 kV	Valliant 345 kV	1
	11155	875	regional reliability	Replace 69 kV switch 11985 and 1033 AAC jumpers at Sugar Hill.	$100,000	AEP		04/01/12	NTC		Sugar Hill 138 kV	Sugar Hill 69 kV	1
20027	10510	392	regional reliability	Rebuild 3.49 miles of Howell - Kilgore 69 kV 4/0 ACSR with 795 ACSR.	$3,986,000	AEP	06/01/12	M		01/27/09	Howell 69 kV	Kilgore 69 kV	1
20000	10505	387	regional reliability	Replace wave trap at Okmulgee.	$125,000	AEP	06/01/12	M		02/13/08	Riverside Station 138 kV	Okmulgee 138 kV	1
20000	10506	388	regional reliability	Replace 2 sets of New Boston switches on terminal to North New Boston.	$100,000	AEP	06/01/12	M		02/13/08	North New Boston 69kV	New Boston 69 kV	1
20000	10509	391	regional reliability	Replace 138 kV wavetraps at both ends. Reset CTs at Lone Star South. Replace138 kV switches & reset relays at Pittsburg.	$300,000	AEP	06/01/12	M		02/13/08	Lone Star South 138 kV	Pittsburg 138 kV	1
20000	10140	113	regional reliability	Convert Red Point-Haughton to 138 kV, 1590 ACSR (includes Red Point terminal & Haughton station conversion).	$9,480,000	AEP	06/01/12	M		02/13/08	Haughton 138 kV	Red Point 138 kV	1
20000	10141	113	regional reliability	Convert Haughton-McDade to 138 kV, 1590 ACSR (includes McDade station conversion).	$19,482,000	AEP	06/01/12	M		02/13/08	Mcdade 138 kV	Haughton 138 kV	1
20000	10786	113	regional reliability	Build new Caplis-McDade 138 kV, 1590 ACSR line	$11,988,400	AEP	06/01/12	M		02/13/08	Mcdade 138 kV	Caplis 138 kV	1
	10834	636	zonal - sponsored	Install new 138 kV line from Chireno to Martinsville	$7,617,000	DETEC	06/01/12				Chireno 138 kV	Martinsville 138 kV	1
20036	10839	638	regional reliability	Reconductor 8.92 mile Nichols - Sedalia 69 kV with 556 ACSR and upgrade CTs.	$3,520,000	EDE	06/01/12	06/01/10	NTC-Modify Timing	01/27/09	SUB 170 - Nichols ST. 69 kV	Sedalia 69 kV	1
20036	10546	420	regional reliability	Replace jumpers on breaker #6950 at Blackhawk Junction with 556 ACSR for rates 73/89 MVA.	$50,000	EDE	06/01/12	M		01/27/09	Jamesville 69 kV	SUB 415 - Blackhawk Junction 69 kV	1
20028	50080	30074	regional reliability	Install (3) 7.2 Mvar capacitors for a total of 21.6 Mvar at Tahlequah West 69 kV.	$779,000	GRDA	07/01/12	M		01/27/09	Tahlequah West 69 kV		
20040	10927	698	Balanced Portfolio	Install terminal equipment at Cleveland Substation	$1,806,000	GRDA	12/31/12	M		06/19/09	Sooner 345 kV	Cleveland 345 kV	1
20021	10385	299	regional reliability	Reconductor line to 1590 ACSR, A = 347, B = 403. $255K/mile @ 8.8 mi.	$4,212,500	GRDA	06/01/12	M		01/16/09	Kansas Tap 161 kV	W Siloam Springs 161 kV	1
20021	10386	299	regional reliability	Reconductor line to 1590 ACSR, A = 347, B = 403. $255K/mile @ 4.2 mi.	$1,700,000	GRDA	06/01/12	M		01/16/09	W Siloam Springs 161 kV	Siloam City 161 kV	1
	10955	718	regional reliability - non OATT	Adding 115 kV line from Sub F - Libory. City of Grand Island Owned Transmission Facility that is NOT under SPP OATT	$3,937,500	GRIS	12/01/12	M			SUB-F 7 115 kV	ST.LIB 7 115 kV	1
	10956	719	regional reliability - non OATT	Upgrade line to 179 MVA. City of Grand Island Owned Transmission Facility that is NOT under SPP OATT.	$200,000	GRIS	04/01/12	M			SUB H 115 kV	SUB E 115 kV	1
20018	10405	313	transmission service	Install new line from Valliant 345 kV to Hugo Power Plant with 19 miles of bundled 795 ACSR conductor	$18,000,000	ITCGP	04/01/12	M		01/16/09	Hugo Power Plant 345	Valliant 345 kV	1
20018	10406	314	transmission service	Install new 345/138 kV transformer	$12,000,000	ITCGP	04/01/12	M		01/16/09	Hugo Power Plant 345 kV	HugoPower Plant 138 kV	1
20042	10934	702	Balanced Portfolio	West Gardner 345kV bus cut-in to Swissvale-Stillwell 345 kV line	$2,000,000	KCPL	06/01/12	M		06/19/09	West Gardner 345 kV		
	10490	377	zonal - sponsored	New Middle Creek sub and Paola-Middle Creek 161kV line	$2,622,850	KCPL	06/01/12	M			Paola 161 kV	Middle Creek 161 kV	1
	10491	378	zonal - sponsored	New North Louisburg-Middle Creek 161kV line	$12,179,000	KCPL	06/01/12	M			North Louisburg 161 kV	Middle Creek 161 kV	1
	10540	414	zonal - sponsored	New Cedar Niles-Clare 161 kV Line & Clare substation	$3,756,500	KCPL		M			Cedar Niles	Clare 161 kV	1
20009	10543	417	regional reliability	Upgrade wavetrap at Gladstone from 800 A to 1200 A	$13,000	KCPL	06/01/12	M		02/13/08	Avondale 161 kV	Gladstone 161 kV	1
	11086	823	regional reliability - non OATT	New substation and transformer 115/69 kV 44 MVA	$1,000,000	LEA		06/01/12			LE_ERF 115 kV	LE_ERF 69 kV	1
	11087	823	regional reliability - non OATT	New Line 69 kV	$1,000,000	LEA		06/01/12			LE_ERF 69 kV	Lea- Ancell 69 kV	1
	11088	823	regional reliability - non OATT	New Line 69 kV	$1,000,000	LEA		06/01/12			LE_ERF 69 kV	Lea- Gaines 69 kV	1
20046	10941	707	Balanced Portfolio	Install new 345/230 kV transformer at Wolf	$3,000,000	MIDW	06/01/12	M		06/19/09	Wolf 345 kV	Wolf 230	1
20007	50104	30098	regional reliability	Install 20 Mvar capacitor bank at Plainville 115 kV.	$1,600,000	MKEC	06/01/12	M		02/13/08	Plainville 115 kV		
	50248	30236	regional reliability	Install 36 Mvar capacitor bank at Kearney 115 kV.	$1,000,000	NPPD	06/01/12	06/01/12	NTC		Kearney 115 kV		
	50207	30200	regional reliability	Add one 15 Mvar cap at Petersburg.	$607,500	NPPD	11/01/12	11/01/12	NTC		Petersburg 115 kV		
	50208	30201	regional reliability	Add one 18 Mvar cap at Clarks 7.	$729,000	NPPD	11/01/12	11/01/12	NTC		Clarks 115 kV		
	50209	30202	regional reliability	Expand existing 9 Mvar cap to 18 Mvar cap at Ainsworth	$50,000	NPPD	11/01/12	11/01/12	NTC		Ainsworth 115 kV		
	50206	30199	zonal - sponsored	Add one 9 Mvar cap at Oneil 69 kV	$364,500	NPPD	11/01/12	11/01/12			Oneill 69 kV		
	50210	30203	regional reliability	Add one 18 Mvar cap at Oneill 115	$729,000	NPPD	11/01/12	11/01/12	NTC		Oneill 115 kV		
	10954	717	zonal - sponsored	Tap CENCITY7 - Silver Creek 115 kV at CLARKS7. Build new 115 kV line from CLARKS7 - CEN.C.N7. Radial 115 kV line for TransCanada Keystone XL project.	$5,625,000	NPPD	11/01/12	M			Clarks 115 kV	CEN.C.N7 115 kV	1
	10969	732	zonal - sponsored	Build new line from Oneill to new STUARTS7. Radial 115 kV line for TransCanada Keystone XL project.	$16,031,250	NPPD	11/01/12	M			Oneill 115 kV	Stuarts 115 kV	1
	10975	738	zonal - sponsored	Build new line from Petersburg to new ERICSON7. Radial 115 kV line for TransCanada Keystone XL project.	$19,687,500	NPPD	11/01/12	M			Petersburg 115 kV	Ericson 115 kV	1
	10986	749	regional reliability	Uprate conductor and terminal equipment to 100 Deg Rating by 2012. 155 MVA normal continuous rating. 155 MVA 4-hour emergency rating.	$2,000,000	NPPD	06/01/12	06/01/12	NTC		Maloney 115 kV	North Platte 115 kV	1
	11080	818	regional reliability	Uprate conductor and terminal equipment to 100 Deg Rating by 2012. 137 MVA normal continuous rating. 137 MVA 4-hour emergency rating.	$1,000,000	NPPD	06/01/12	06/01/12	NTC		Loup City 115 kV	North Loup 115 kV	1
	11151	629	regional reliability	Build new 5.5 miles double circuit line from Twin CH- new South Sioux City sub. Includes rebuild of Twin Church sub and new South Sioux City sub.		NPPD	06/01/12	M	NTC		Twin Church 115 kV	South Sioux City 115 kV	1
	11206	629	zonal - sponsored	Rate B was increased from 88 MVA to 99 MVA by replacing substation terminal equipment.	$33,000,000	NPPD	12/31/08	M			Twin Church 115 kV	Belden 115 kV	1
	11152	629	regional reliability	Build new 5.5 miles double circuit line from Twin CH- new South Sioux City sub. Includes rebuild of Twin Church sub and new South Sioux City sub.		NPPD	06/01/12	M	NTC		Twin Church 115 kV	South Sioux City 115 kV	2
20029	10749	583	regional reliability	Install new tap for Adabell substation.	$4,972,000	OGE	03/31/12	M		01/27/09	VBI 161 kV	Adabell 161 kV	1
20029	10749	583	regional reliability	Install new tap for Adabell substation.	$4,972,000	OGE	03/31/12	M		01/27/09	Alcoa Tap 161 kV	Adabell 161 kV	1
20055	10668	523	regional reliability	New 345 kV line from Sooner to Oklahoma/Kansas Stateline or the interface with the Westar Energy line segment to achieve 3000	$45,000,000	OGE	06/01/12	M		09/18/09	Sooner 345 kV	Rose Hill 345 kV	1
20041	10929	699	Balanced Portfolio	Build new 345 kV line from Sooner to Cleveland. Install terminal equipment at Sooner	$47,200,000	OGE	12/31/12	M		06/19/09	Sooner 345 kV	Cleveland 345 kV	1
20017	50169	30161	transmission service	Add 345 kV line from Sunnyside to WFEC interception of 345 kV line from Hugo, install 345 kV breaker, switches, and relays at Sunnyside.	$200,000,000	OGE	04/01/12	M		01/16/09	Hugo 345 kV	Sunnyside 345 kV	1
20017	50171	30163	transmission service	Add 2nd 345/138 kV Auto Transformer	$10,000,000	OGE	04/01/12	M		01/16/09	Sunnyside 345 kV	Sunnyside138 kV	2
	10837	551	regional reliability	Install 2 miles of 161 kV from Johnson to Oak Park and install terminal equipment at Oak Park.	$3,200,000	OGE	06/01/12	06/01/12	NTC		Oak Park 161 kV	Johnson 161 kV	1
	10701	551	regional reliability	Convert 5.6 miles of 69 kV to 161 kV.	$5,500,000	OGE	06/01/12	06/01/12	NTC		Johnson 161 kV	Massard 161 kV	1
	11002	759	zonal - sponsored	Replace terminal equipment so that the overall facility rating is 352 MVA.	$565,000	OPPD	11/10/12	11/10/12			SUB 1221 161 kV	S1255 161 kV	1
20058	50110	30104	regional reliability	Add 24 Mvar Cap bank at North Cimarron	$2,500,000	SEPC	06/01/12			09/18/09	North Cimarron 115 kV		
20045	10939	706	Balanced Portfolio	Build new 345 kV line from Spearville to interception point of Spearville to Knoll line.	$54,000,000	SEPC	06/01/12	M		06/19/09	Spearville 345 kV	Wolf 345 kV	1
	11102	835	regional reliability	Move load from 69 to 115 kV bus	$16,245,000	SPS	11/17/12	06/01/14			EST Clovis 69 kV	E Clovis 115 kV	1
	11103	835	regional reliability	Reconductor 5.35 mile FE-Clovis to Curry CKT 1 with 397.5 ACSR.	$2,257,031	SPS	12/17/12	06/01/14			FE-Clovis 115 kV	FE-Holland 115 kV	1
	11056	797	regional reliability	Add second 230/138kV transformer at Borden County by moving old from Midland when retired.	$11,250,000	SPS	03/21/12	06/01/10	NTC		Caprock REC-Vealmoor 138 kV	Borden County Interchange 230 kV	2
	11045	791	regional reliability	New 15 mile Lampton Interchange - Hart Industrial Substation 115 kV line.	$8,438	SPS	12/16/12	06/01/10	NTC		Lamton Interchange 115 kV	Hart Industrial 115 kV	1
	11041	791	regional reliability	New 19 mile Swisher County Interchange - Newhart 230 kV line.	$16,031,250	SPS	12/16/12	06/01/10	NTC		Newhart 230 kV	Swisher County Interchange 230 kV	1
	11042	791	regional reliability	New 18 mile Kress - Newhart 115 kV line.	$10,125,000	SPS	12/16/12	06/01/10	NTC		Kress Interchange 115 kV	Newhart 115 kV	1
	11043	791	regional reliability	New 24 mile Castro County Interchange - Newhart 115 kV line.	$13,500,000	SPS	12/16/12	06/01/10	NTC		Castro County Interchange 115 kV	Newhart 115 kV	1
	11089	824	regional reliability	Convert existing 89.22 mile Hobbs - Midland 230 kV line to operate at 345 kV.	$4,725,000	SPS	01/21/12	06/01/10	NTC		Hobbs 345 kV	Midland 345 kV	1
	11021	774	regional reliability	Convert Hastings Sub from 69kV to 115 kV	$5,062,500	SPS	08/18/12	06/01/10	NTC		Hastings 115 kV	Hastings 115 kV	
	11022	774	regional reliability	New 5 mile Hastings - Bush 115 kV line.	$2,200,000	SPS	09/01/12	06/01/10	NTC		Hastings 115 kV	Bush Sub 115 kV	1
	11038	789	regional reliability	Reconductor .27 mile Roswell Interchange - Brasher Tap 115 kV with 397 kcmil conductor.	$114,000	SPS	05/26/12	06/01/12	NTC		Roswell Interchange 115 kV	Brasher Tap	1
	11085	704	Balanced Portfolio	Add second 345/230/13.2 kV Tuco Interchange 515/560 MVA transformer.	$11,250,000	SPS		06/01/12	NTC-Modify Timing	06/19/09	Tuco Interchange 345 kV	Tuco Interchange 230 kV	2
	11052	795	regional reliability	New 230/115kV transformer at Frio-Draw substation.	$11,250,000	SPS	05/21/12	06/01/11	NTC		Frio-Draw 230kV	Frio-Draw 115 kV	1
	11053	795	regional reliability	Build new 16 mile Frio-Draw - Oasis 230kV line.	$13,500,000	SPS	05/21/12	06/01/11	NTC		Frio-Draw 230kV	Oasis Interchange 230 kV	1

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	11054	795	regional reliability	Build new 26 mile Frio-Draw - Roosevelt County 230kV line.	$21,937,500	SPS	11/17/12	06/01/11	NTC		Frio-Draw 230kV	Roosevelt County Interchange 230 kV	1
	11176	887	regional reliability	Build new 9 mile Canyon West - Spring Draw 115 kV line.	$7,762,500	SPS	12/16/12	6/1/2010	NTC		Canyon West 115 kV	Spring Draw 115 kV	1
	11177	888	regional reliability	Build new 20 mile Randall Co - Amarillo South 230 kV line.	$27,450,000	SPS	12/16/12	6/1/2010	NTC		Randall Co 230 kV	Amarillo South 230 kV	1
	10835	102	regional reliability - non OATT	Upgrade Nixa #2 transformer to 70 MVA	$1,575,000	SWPA		06/01/18			Nixa 161 kV	Nixa 69 kV	2
	50294	30257	regional reliability - non OATT	10 Mvar cap at Gregory WAPA	$405,000	WAPA	06/01/12				Gregory 115 kV		
	50296	30258	regional reliability - non OATT	21.6 Mvar cap at Martin WAPA	$874,800	WAPA	06/01/12				Martin 115 kV		
	50297	30259	regional reliability - non OATT	30 Mvar cap bank at PHILLIPS WAPA	$1,215,000	WAPA	06/01/12				Phillips 115 kV		
19985	50047	30041	regional reliability	Install 12 Mvar capacitor at Comanche 138 kV bus.	$350,000	WFEC	06/01/12	M		02/02/07	Comanche 138 kV		
20003	50099	30093	regional reliability	Install 12 Mvar capacitor at Latta Junction 138 kV.	$324,000	WFEC	06/01/12	M		02/13/08	Latta Junction 138 kV		
20018	50173	30165	transmission service	Install 345 kV breaker at Hugo	$2,000,000	WFEC	04/01/12	M		01/16/09	Hugo 345 kV	Sunnyside 345 kV	1
20003	10522	402	regional reliability	Convert 3 miles of 69 kV to 138 kV from Indiahoma to Grandfield.	$1,125,000	WFEC	06/01/12	M		02/13/08	Grandfield 138 kV	Indiahoma 138 kV	1
20003	10523	402	regional reliability	Tap Cache to Paradise 138 kV and install 13.7 miles of 138 kV from Cache to Indiahoma.	$7,306,000	WFEC	06/01/12	M		02/13/08	Indiahoma 138 kV	Cache SW 138 kV	1
20003	10524	402	regional reliability	Install new 138/69 kV transformer at Grandfield	$5,000,000	WFEC	06/01/12	M		02/13/08	Grandfield 138 kV	Grandfield 69 kV	1
20003	10519	399	regional reliability	Upgrade line from 1/0 to 336.4, 4.85 miles	$1,347,000	WFEC	06/01/12	M		02/13/08	Lindsay 69 kV	Wallville 69 kV	1
20003	10520	400	regional reliability	WFEC will upgrade 800 A CTs, new CT limit will be 1200 A at Pharaoh.	$225,000	WFEC	06/01/12	M		02/13/08	Pharoah 138 kV	Weleetka 138 kV	1
20003	10521	401	regional reliability	Replace CT at WFEC Russell	$50,000	WFEC	06/01/12	M		02/13/08	WFEC Russell 138 kV	AEP Altus Jct Tap 138 kV	1
	10878	672	regional reliability	Reconductor 6.5 miles of 1/0 conductor with 336.4 ACSR.	$1,950,000	WFEC		06/01/12	NTC		El Reno 69 kV	El Reno SW 69 kV	1
20006	50102	30096	Zonal Reliability	Install 20 Mvar capacitor bank at Eudora 115 kV.	$580,000	WR	06/01/12	M		02/13/08	Eudora 115 kV		
20059	50229	30225	transmission service	Add 15 Mvar Cap bank at Allen	$607,500	WR	06/01/12			09/18/09	Allen 69 kV		
	50295	30256	zonal - sponsored	Install 2nd block of 14.4 Mvar	$1,120,000	WR	06/01/12	M			Clearwater 138 kV		
20033	10602	463	regional reliability	The East Manhattan-McDowell 115 kV is built as a 230 kV line but is operated at 115 kV. Substation work will have to be performed in order to convert this line to 230 kV operation..	$4,100,000	WR	06/01/12	M		01/27/09	East Manhattan 230kV	McDowell 230kV	1
	10995	754	zonal - sponsored	Build a new 138kV line from Clearwater and a new 138kV line from Evans to serve the new Goddard substation	$5,625,000	WR	06/01/12	M			Clearwater 138 kV	Goddard 138 kV	1
	10996	754	zonal - sponsored	Build a new 138kV line from Clearwater and a new 138kV line from Evans to serve the new Goddard substation	$5,625,000	WR	06/01/12	M			Evans Energy Center South 138 kV	Goddard 138 kV	1
20059	50228	30224	transmission service	Rebuild approximately 6 miles of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating	$2,560,500	WR	06/01/12			09/18/09	Allen 69 kV	Lehigh Tap 69 kV	1
20006	10221	172	regional reliability	Convert TEC-Midland from 161 kV to 115 kV	$2,100,000	WR	06/01/12	M		02/13/08	Tecumseh Energy Center 115 kV	Midland 115 kV	1
19964	10488	375	transmission service	Install 3rd Rose Hill 345/138 kV TRANSFORMER.	$8,100,000	WR	06/01/12	M		06/27/07	Rose Hill 345 kV	Rose Hill 138 kV	3
20063	10670	664	regional reliability	Tear down and rebuild 1.8 mile Gill Energy Center West - Waco 138 kV with bundled 1192.5 ACSR conductor.	$1,000,000	WR	06/01/12	06/01/13		11/02/09	Gill Energy Center West 138 kV	Waco 138 kV	1
						Year 2013							
20027	10575	443	regional reliability	Tap the South Springdale-East Fayetteville 161 kV line and build 1.5 miles of 161 kV to new Osbourne station.	$2,000,000	AEP	06/01/13	M		01/27/09	Osbourne 161 kV	Osbourne Tap 161 kV	1
	10695	546	regional reliability	Rebuild the 26.2 mi Carnegie - Hobart Jct. 138 kV line from 397 ACSR to 1272 ACSR. Replace 3 switches, wave traps and jumpers. Reset CTs and relays.	$26,150,000	AEP		06/01/13	NTC		Hobart Junction 138 kV	Carnegie 138 kV	1
	10696 & 10697	546	regional reliability	Reconductor the 14.37 mile Southwest Station - Carnegie 138 kV line from 795 ACSR to 1272 ACSR. Replace wave traps and jumpers.	$11,030,000	AEP		06/01/13	NTC		Carnegie 138 kV	Southwest Station 138 kV	1
20064	11015	770	regional reliability	Rebuild 2.45 miles of 795 ACSR with 1590 ACSR and reset relays.	$2,500,000	AEP	06/01/13			11/02/09	Ashdown 138 kV	Craig Junction 138 kV	1
20057	10687	539	transmission service	Brookline: Replace 1,200 amp switches with 2,000 amp units and replace metering CTs. Junction: Replace 1,200 amp switches with	$120,000	CUS	06/01/13	06/01/19		09/18/09	Brookline 161 kV	Junction 161 kV	1
20034	10847	646	regional reliability	Replace Clinton 161/69 kV transformer #1 with new 100/125 MVA to match transformer #2.	$2,000,000	GMO	06/01/13	M		01/27/09	Clinton 69 kV	Clinton 161 kV	1
	10430	333	zonal - sponsored	161kV Tap of Hallmark to Sibley	$302,795	GMO	06/01/13	M			Ritchfield 161	Sibley 161	1
	10432	335	zonal - sponsored	161kV Tap of Hallmark to Sibley	$0	GMO	06/01/13	M			Hallmark 161	Ritchfield 161	1
	10541	414	zonal - sponsored	New Quarry-Clare 161 kV Line	$1,385,000	KCPL	06/01/13	M			Quarry 161 kV	Clare 161 kV	1
	10544	418	zonal - sponsored	New Waldron sub cut-in	$1,632,300	KCPL	06/01/13	M			Waldron 161 kV	Maywood 161 kV	1
	10545	418	zonal - sponsored	New Waldron sub cut-in		KCPL	06/01/13	M			Waldron 161 kV	Weatherby 161 kV	1
	10952	715	regional reliability	Reconductor GMO portion of Glenare - Liberty 69 kV for 70/79 MVA rating.	$200,000	KCPL		06/01/13	NTC		Glenare 69 kV	Liberty 69 kV	1
	10948	711	zonal - sponsored	Add NW68th Holdrege 345/115kV Transformer #2. Driven by NERC Category C (TPL-003) - prior outage of one 345/115kV transformer, followed by an outage of a second 345/115kV transformer.	$11,250,000	LES	05/31/13	M			NW68 & HOLDRIDGE 115 kV	Nw68 & Holdridge 345 Kv	1
20046	10940	707	Balanced Portfolio	Build new 345 kV line from Knoll to interception point of Spearville to Knoll line.	$42,000,000	MIDW	06/01/13	M		06/19/09	SPEARVILLE 345 kV	Wolf 345 kV	1
20046	10943	707	Balanced Portfolio	Build new 345 kV line from Knoll to interception point of Axtell to Knoll line.	$66,000,000	MIDW	06/01/13	M		06/19/09	Axtell 345 kV	Wolf 345 kV	1
20032	10914	697	regional reliability	Rebuild 21.1 mile HEC - Huntsville 115 kV line and replace CT, wave trap and relays.	$6,250,000	MIDW		06/01/13		01/27/09	Hutchinson Energy Center 115 kV	Huntsville 115 kV	1
	10858	653	regional reliability	Rebuild 21.9 mile St. John - Pratt 115 kV line with 795 ACSR conductor.	$9,239,000	MKEC		06/01/13	NTC		St. John 115 kV	Pratt 115 kV	1
	50213	30206	regional reliability	Install 9 Mvar capacitor bank at Gordon 115 kV.	$1,000,000	NPPD	06/01/12	06/01/13	NTC		Gordon 138 kV		
20047	10942	708	Balanced Portfolio	Build new 345 kV line from Axtell to interception point of Axtell to Wolf line (Kansas Border). Includes substation expansion at Axtell and line reactor.	$76,000,000	NPPD	06/01/13	M		06/19/09	Axtell 345 kV	Wolf 345 kV	1
	11079	817	regional reliability	Uprate line and substation equipment to 100 Deg C Rating by 2013. 174 MVA Normal Continuous Rating. 174 MVA 4-Hour Emergency Rating.	$1,000,000	NPPD	06/01/13	06/01/13	NTC		Albion 115 kV	Spalding 115 kV	1
20029	10843	642	regional reliability	Remove wavetrap at VBI.	$10,000	OGE	06/01/13			01/27/09	Kilgore 69 kV	VBI 69 kV	1
	10300	235	regional reliability	Reconductor 2.2 miles to 1590 kmcm ACSR and change terminal equipment at Ft. Smith and Colony substations to 2000A.	$2,500,000	OGE	06/01/13	06/01/13	NTC		Fort Smith 161 kV	Colony 161 kV	1
20041	10930	700	Balanced Portfolio	Build new 345 kV line from Seminole to Muskogee	$131,000,000	OGE	12/31/13	M		06/19/09	Seminole 345 kV	Muskogee 345 kV	1
20041	10931	700	Balanced Portfolio	Install 3rd 345/138 kV transformer at Seminole	$4,000,000	OGE	12/31/13	M		06/19/09	Seminole 138 kV	Seminole 345 kV	3
	11139	862	regional reliability	Rebuild 2 mile Sub 906 North - Sub 928 line. Change CT tap settings, and replace line jumpers for 110 MVA rating.	$4,638,000	OPPD		06/01/13	NTC		SUB 906 North 69 kV	SUB 928 69 kV	1
	11141	864	regional reliability	Increase line clearances to allow the use of a higher conductor rating.	$272,000	OPPD		06/01/13			SUB 907 69 kV	Sub 919 69 kV	1
	11044	791	regional reliability	Build new 4 mile Hart Industrial Substation - Newhart Substation 115 kV line.	$2,250,000	SPS	03/16/13	06/01/10	NTC		Hart Industrial 115 kV	Newhart 115 kV	1
	11023	774	regional reliability	Build new 3.7 mile Hastings - East Plant 115kV line.	$1,700,000	SPS	03/16/13	06/01/10	NTC		Hastings Sub 69 kV	East Plant Interchange 115 kV	1
	11047	793	regional reliability	Reconductor 5.5 mile Gains County Interchange - Legacy 115 kV line.	$2,320,300	SPS		06/01/13	NTC		Gaines County Interchange 115 kV	Legacy 115 kV	1
	11050	795	regional reliability	Build new 130 mile 345 kV line from Potter to new Frio-Draw substation at Roosevelt.	$146,250,000	SPS	12/31/13	06/01/13	NTC		Frio-Draw 345kV	Potter County Interchange 345 kV	1
	11051	795	regional reliability	Build new Frio-Draw substation with 345/230 kV transformer.	$11,250,000	SPS	12/31/13	06/01/13	NTC		Frio-Draw 345 kV	Frio-Draw 230kV	1
	11049	794	regional reliability	Add a second Grave 115/69 kV transformer.	$900,000	SPS	06/01/13	06/01/13	NTC		GRAVE 3 115 kv	Grave 2 69 kV	2
	11101	834	regional reliability	Convert existing 3 mile Portales Interchange - Zodiac 69 kV line to operate at 115 kV.	$3,487,500	SPS	05/21/13	06/01/13	NTC		Portales Interchange 115 kV	Zodiac 115 kV	1
	10841	640	regional reliability - non OATT	Resag conductor and replace some structures.	$50,000	SWPA		M			Malden 69 kV	New Madrid 69 kV	1
	11014	769	regional reliability - non OATT	Replace bus and CTs at Norfolk.	$112,500	SWPA		06/01/13			Norfolk 161 kV	Southland 161 kV	1
20030	50186	30178	regional reliability	Install 6 Mvar capacitor bank at Electra 69 kV bus for a total of 18 Mvar at this location.	$240,000	WFEC	06/01/13	06/01/11	NTC-Modify Timing	01/27/09	Electra 69 kV		
	11115	846	regional reliability	Rebuild 25.2 mile Anadarko - Blanchard 69 kV as 138 kV.	$14,737,500	WFEC		06/01/13	NTC		Anadarko 138 kV	Blanchard 138 kV	1
	11116	846	regional reliability	Rebuild 2 mile Blanchard - OU Switchyard 69 kV as 138 kV.	$1,125,000	WFEC		06/01/13			Blanchard 138 kV	OU Switchyard 138 kV	1
20006	50111	30105	Zonal Reliability	Install 30 Mvar capacitor at Springhill 115 kV.	$1,000,000	WR	06/01/13	M		02/13/08	Springhill 115 kV		
20059	50231	30227	transmission service	Add 15 Mvar Cap bank at Athens	$607,500	WR	06/01/13			09/18/09	Athens 69 kV		
	50298	30260	zonal - sponsored	1 stage of 10.8 Mvar	$432,000	WR	06/01/13	M			Scranton 115 kV		
	50299	30261	zonal - sponsored	1 stage of 10.8 Mvar	$432,000	WR	06/01/13	M			Shawnee Heights 115 kV		
	10603	467	regional reliability	Replace wave traps on Gill - Interstate 138 kV line for a new rating of 232/256 MVA.	$50,000	WR		06/01/13	NTC		Gill Energy Center East 138 kV	Interstate 138 kV	1
20033	10844	643	regional reliability	Tap the Neosho - Twin Valley line into Altamont.	$4,000,000	WR	06/01/13	M		01/27/09	TWIN VALLEY NO. 1 MOUND VALLEY 138 K	Neosho 138 kV	1
20063	10846	645	regional reliability	Add second transformer in 17th Street substation.	$2,400,000	WR	06/01/13	M		11/02/09	17TH Street 4 138 kV	17TH Street 2 69 kV	1
20033	10678	533	regional reliability	Install second Auburn Road 230/115 kV transformer.	$12,622,500	WR	06/01/13	06/01/15	NTC-Modify Timing	01/27/09	Auburn 230 kV	Auburn 115 kV	2
	11062	819	regional reliability	Rebuild 5.56 mile Gill Energy Center East - MacArthur 60 kV line. Replace substation bus and jumpers at MacArthur 69 kV.	$3,127,500	WR		06/01/13	NTC		Gill Energy Center East 69 kV	Macarthur 69 kV	1
20059	50233	30224	transmission service	Rebuild approximately 7 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.	$3,340,000	WR	07/01/13			09/18/09	Burlington Junction 69 kV	Coffey County No. 3 Westphalia 69 Kv	1
20059	50234	30224	transmission service	Rebuild approximately 4 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.	$1,945,000	WR	01/01/13			09/18/09	Burlington Junction 69 kV	Wolf Creek 69 kV	1
20059	50240	30224	transmission service	Rebuild approximately 1 mile of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating.	$593,775	WR	11/01/13			09/18/09	LEHIGH TAP 69 KV	United No. 9 Conger 69 kV	1
20059	10674	529	regional reliability	New 345 kV line from Oklahoma/Kansas Stateline or the interface with the OG&E line segment to Rose Hill to achieve 3000 amp or	$84,669,696	WR	01/01/13	M		09/18/09	Sooner 345 kV	Rose Hill 345 kV	1
						Year 2014							
20000	10584	450	regional reliability	Install 345/161 kV transformer at Shipe Road.	$13,104,000	AEP	06/01/14	M		02/13/08	Shipe Road 345 kV	Shipe Road 161 kV	1
20000	10585	450	regional reliability	Install 22 miles of new 345 kV, 2-954 ACSR line.	$34,085,000	AEP	06/01/14	M		02/13/08	Flint Creek 345 kV	Shipe Road 345 kV	1
20000	10582	450	regional reliability	Install 2 miles of 161 kV from new Shipe Road Substation to East Centerton Substation.	$11,962,000	AEP	06/01/14	M		02/13/08	Shipe 161 kV	East Centerton 161 kV	1
20027	10853	649	regional reliability	Reconductor 2.15 mile section of 115 kV line with 795 ACSR.	$2,150,000	AEP	06/01/14	M		01/27/09	Lone Star 115 kV	Locust Grove 115 kV	1

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	10577	445	regional reliability	Rebuild 5.4 mile Big Sandy - Perdue 69 kV line from 477 ACSR to 1272 ACSR.	$5,400,000	AEP	06/01/14	06/01/15			Big Sandy 69 kV	Perdue 69 kV	1
	11153	873	regional reliability	Upgrade 600 A breaker and two switches at Texarkana Plant.	$250,000	AEP		06/01/14			SE Texarkana 69 kV	Texarkana 69 kV	1
	11169	880	regional reliability	Upgrade 2 sets of switches at Rock Hill and 1 set of switches at Beckville bus.	$200,000	AEP		06/01/14			Beckville 69 kV	Rock Hill 69 kV	1
	10849	648	zonal - sponsored	Covert from 59 kV to 138 kV	$8,837,000	DETEC	06/01/14				Martinsville 138 kV	Shady Grove 138 kV	1
	10850	648	zonal - sponsored	Covert from 59 kV to 138 kV		DETEC	06/01/14				Shady Grove 138 kV	Central Hieghts 138 kV	1
	10851	648	zonal - sponsored	Covert from 59 kV to 138 kV		DETEC	06/01/14				Central Hieghts 138 kV	Fitze 138 kV	1
	10852	648	zonal - sponsored	Covert from 59 kV to 138 kV		DETEC	06/01/14				Fitze 138 kV	Tempson 138 kV	1
	11074	812	regional reliability	Replace jumpers.	$100,000	EDE		06/01/14			SUB 403 - Jasper West Tap 69 kV	SUB 249 - Boston East 69 kV	1
	11073	811	regional reliability	Raise structures on Diamond Jct. - Sarcoxie Southwest 69 kV line to achieve a new rating B of 44 MVA.	$50,000	EDE		06/01/14			SUB 131 - Diamond Junction 69 kV	SUB 362 - Sarcoxie Southwest 69 kV	1
	10567	437	regional reliability	Replace switch on transfer bus at Sub# 167 for Rate B = 91 MVA.	$75,000	EDE	06/01/14	06/01/15			Sub 167 - Riverton 69 kV	SUB 278 - Galena Northeast 69 kV	1
20036	10258	202	regional reliability	Reconductor 1.0 Mile of 4/0 ACSR with 336 ACSR for 65 MVA Rate B	$400,000	EDE		06/01/14		01/27/09	SUB 436 - Webb City Cardinal 69 kV	SUB 110 - Oronogo Junction 69 kV	1
	50260	30247	regional reliability	Install 7.2 Mvar capacitor bank at Wagner 69 kV.	$291,600	GRDA		06/01/14			Wagoner 69 kV		
	10633	489	regional reliability	Rebuild 26.55 mile Huntsville - St. John 115 kV line and replace CT, wavetrap, breakers, and relays.	$5,250,000	MIDW		06/01/14			Huntsville 115 kV	St. John 115 kV	1
	50249	30237	regional reliability	Install 18 Mvar capacitor bank at Holdrege 115 kV.	$1,000,000	NPPD	06/01/14	06/01/14			Holdrege 115 kV		
	11078	816	regional reliability	Uprate line and substation equipment to effect 100 Deg C Rating by 2014. 137 MVA Normal Continuous Rating. 137 MVA 4-Hour Emergency Rating.	$1,000,000	NPPD	06/01/14	06/01/14			Albion 115 kV	Genoa 115 kV	1
	11143	889	regional reliability	Increase line clearances to allow the use of a higher conductor rating. Change CT tap settings.	$251,000	OPPD		06/01/14			Sub 921 69 kV	Sub 942 69 kV	1
	11137	860	regional reliability	Increase line clearances to allow the use of a higher conductor rating.	$105,000	OPPD		06/01/14			SUB 901 69 kV	Junction 205 69 kV	1
	11138	861	regional reliability	Increase line clearances to allow the use of a higher conductor rating.	$251,000	OPPD		06/01/14			SUB 910 69 kV	Junction 205 69 kV	1
	11142	865	regional reliability	Increase line clearances to allow the use of a higher conductor rating.	$253,000	OPPD		06/01/14			Sub 917 69 kV	Sub 918 69 kV	1
	11191	897	zonal - sponsored	New Distribution Sub - WR Airport		OGE	06/01/14	M			36 & Meridian 138 kV	WRAirport 138 kV	1
	11192	897	zonal - sponsored	New Distribution Sub - WR Airport		OGE	06/01/14	M			WRAirport 138 kV	Pennsylvania 138 kV	1
20041	10932	701	Balanced Portfolio	Build new 345 kV line from Woodward EHV to Border	$105,000,000	OGE	05/19/14	M		06/19/09	Stateline 345 kV	Woodward EHV 345kv	1
20041	10933	701	Balanced Portfolio	Install 2nd 345/138 kV transformer at Woodward EHV	$15,000,000	OGE	05/19/14	M		06/19/09	Woodward EHV 138 kV	Woodward EHV 345 kV	2
	50275	30262	regional reliability	Install 7.2 Mvar at Canadian Sub	$291,600	SPS		06/01/14			Canadian 115 kV		
	11055	796	regional reliability	Add second 230/115 kV transformer at Grassland Interchange.	$11,250,000	SPS		06/01/14			Grassland Interchange 115 kV	Grassland Interchange 230 kV	2
20043	10936	704	Balanced Portfolio	Build new 345 kV line from Tuco to Border	$122,597,500	SPS	05/19/14	M		06/19/09	Tuco Interchange 345 kV	Stateline 345 kV	1
20043	10937	704	Balanced Portfolio	Build Border at interception point of Woodward to Tuco line.	$14,880,000	SPS	05/19/14	M		06/19/09	Stateline 345 kV		
	11007	764	regional reliability	Upgrade both Happy County 115/69 kV transformers to 84 MVA.	$1,890,000	SPS	06/01/14	06/01/14			Happy Interchange 115 kV	Happy Interchange 69 kV	1
	11009	764	regional reliability	Upgrade both Happy County 115/69 kV transformers to 84 MVA.	$1,890,000	SPS	06/01/14	06/01/14			Happy Interchange 115 kV	Happy Interchange 69 kV	2
	11093	826	regional reliability	Replace existing 149/171 MVA Chaves 230/115 kV transformer with 225 MVA transformer.	$11,250,000	SPS	06/01/14	06/01/14			Chaves 115 kV	Chaves 230 kV	2
	11104	836	regional reliability	Move load from Muleshoe 69 kV to Muleshoe 115 kV.	$3,318,750	SPS	06/01/14	06/01/14			Muleshoe 69 kV	Muleshoe E 115 kV	1
	11107	839	regional reliability	Build new 22.2 mile Kress Interchange - Plainview County 115 kV.	$14,737,500	SPS	06/01/14	06/01/14	NTC		Kress Int 115 kV	Plainview CTY 115 kV	1
	11108	839	regional reliability	Add new Plainview County 115/69 kV transformer with 44/50.6 MVA ratings.	$990,000	SPS	06/01/14	06/01/14	NTC		Plainview Co 69 kV	Plainview CTY 115 kV	1
	11109	840	regional reliability	Build new 9.8 mile Cox - Plainview 115 kV line unit.	$7,762,500	SPS	06/01/15	06/01/14	NTC		Cox 115 kV	Plainview CTY 115 kV	1
	11122	852	regional reliability	Replace wave trap with 1200 A minimum.	$225,000	SPS	06/01/14	06/01/14			Jones 230 kV	Grassland 230 kV	1
	11172	883	regional reliability	Build new second Jones - Grassland 230 kV line.	$30,395,000	SPS	05/16/14	06/01/11	NTC		Jones 230 kV	Grassland 230 kV	2
	11197	900	regional reliability	Reconductor FRIO-DRAW 0.56 miles 115 kV to 795 ACSR line	$315,000	SPS		06/01/14			Frio Draw 115 kV	Farmers Electric REC-Clovis 115 kV	1
	50119	30113	regional reliability - non OATT	Install 30 Mvar capacitor at Glencoe 161 kV substation.	$1,215,000	SWPA	06/01/14	06/01/14			Glencoe 161 kV		
	10819	631	regional reliability - non OATT	Reconductor line to 335/335 MVA.	$10,095,750	SWPA		06/01/14			Asherville 161 kV	Idalia 161 kV	1
	10856	651	regional reliability - non OATT	Replace both Carthage auto transformers with larger units.	$5,625,000	SWPA		06/01/14			Carthage 161 kV	Carthage 69 kV	1 & 2
20003	50045	30039	regional reliability	Install 6 Mvar capacitor at Esquandale 69 kV.	$243,000	WFEC	06/01/14	M		01/27/09	Esquandale 69 kV		
	10669	524	regional reliability	Reconductor 3 mile Gypsum - Russell 69 kV line from 1/0 to 336.4 ACSR.	$900,000	WFEC		06/01/14			Gypsum 69 kV	Russell 69 kV	1
20059	50230	30226	transmission service	Add 6 Mvar Cap bank at Altoona East	$607,500	WR	06/01/14			09/18/09	Altoona East 69 kV		
20063	10713	563	regional reliability	Replace 69 kV disconnect switches at Aquarius with a minimum 600 amp emergency rating	$75,000	WR	06/01/13	M		11/02/09	Litchfield 69 kV	Aquarius 69 kV	1
20033	10679	534	regional reliability	Replace Halstead 138/69/13.2 kV transformer with 100/110 MVA unit.	$1,400,000	WR	06/01/14	06/01/11	NTC-Modify Timing	01/27/09	Halstead South 138 kV	Halstead 69 kV	1
	10605	469	zonal - sponsored	Reset CTs on Moundridge - Newton 69 kV line (multiple rating changes).	$20,000	WR		M			Gatz 69 kV	Newton 69 kV	1
	10997	755	regional reliability	Tear down and rebuild 6.6 mile County Line - Goodyear Junction 115 kV line.	$3,712,500	WR		06/01/14			County Line 115 kV	Goodyear Junction 115 kV	1
20059	50236	30224	transmission service	Rebuild approximately 9 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.	$4,249,000	WR	04/01/14			09/18/09	Green 69 kV	Coffye County No. 3 Westphalia 69 kV	1
						Year 2015							
	11156	876	regional reliability	Rebuild 0.9 mile Weatherford - Thomas Tap 69 kV line from 4/0 ACSR with 795 ACSR. Replace Weatherford wavetrap.	$1,000,000	AEP		06/01/15			Weatherford 69 kV	Thomas Tap 69 kV	1
20036	10685	537	regional reliability	Build new 9.2 mile Substation 383 - Monett 5 161 kV line.	$7,369,319	EDE	06/01/15	06/01/19	NTC-Modify Timing	01/27/09	SUB 383 - Monett 161kV	South Monett 161 kV	1
20036	10686	537	regional reliability	Install 3-winding transformer connecting new 161 kV bus to Monett City South 69 kV.	$8,000,000	EDE	06/01/15	06/01/19	NTC-Modify Timing	01/27/09	South Monett 161 kV	SUB 376 - Monett City South 69 kV	1
	10681	536	regional reliability	Reconductor 1.2 mi with 336 ACSR.	$275,000	EDE	06/01/15	06/01/18			Monett City South Jct. 69 kV	Monett City East 69 kV	1
20042	10935	703	Balanced Portfolio	Tap Nashua 345kV bus in Hawthorn - St. Joseph 345 kV line. Build new 345 kV line from Iatan to Nashua.	$54,444,000	KCPL	06/01/15	M		06/19/09	Iatan 345 kV	Nashua 345 kV	1
20042	10945	703	Balanced Portfolio	Install new 345/161 kV transformer at Nashua	$4,620,000	KCPL	06/01/15	M		06/19/09	Nashua 345 kV	Nashua 161 kV	1
	50198	30191	regional reliability	Install 3 additional Mvar cap at Kinsley 115 kV for a total 8 Mvar	$180,000	MIDW		06/01/15			Kinsley 115 kV		
	50199	30192	regional reliability	Install 3 additional Mvar cap at Pawnee 115 kV for a total 8 Mvar	$180,000	MIDW		06/01/15			Pawnee 115 kV		
	11000	757	regional reliability	Reconductor 12.08 mile FPL Switch to Woodward District line to 1590 AS52.	$4,200,000	OGE		06/01/15			Windfarm 138 kV	Woodward District 138 kV	1
	10876	670	regional reliability	Install third Arcadia 345/138 kV autotransformer.	$12,000,000	OGE		06/01/15			Arcadia 345 kV	Arcadia 138 kV	3
	11129	858	regional reliability	Convert 14 mile Mehan - Cushing 69 kV line to 138 kV.		OGE		06/01/15			Mehan 138 kV	Cushing 138 kV	1
	11130	858	regional reliability	Convert 6 mile Stillwater - Spring Valley 69 kV line to 138 kV.		OGE		06/01/15			Stillwater 138 kV	Spring Valley 138 kV	1
	11131	858	regional reliability	Convert 3 mile Spring Valley - Mehan 69 kV line to 138 kV.		OGE		06/01/15			Spring Valley 138 kV	Mehan 138 kV	1
	11132	858	regional reliability	Convert 8.7 mile Spring Valley - Knipe 69 kV line to 138 kV.	$16,000,000	OGE		06/01/15			Spring Valley 138 kV	Knipe 138 kV	1
	11133	858	regional reliability	Tap existing Cushing - Bristow 138 kV line into new Greenwood Sub 138 kV transformer bus and add new Greenwood 138/69/13.8 transformer.		OGE		06/01/15			Cushing 138 kV	Bristow 138 kV	1
	11134	858	regional reliability	Tap existing Oak Grove - Hwy 99 Tap 69 kV circuit into new Greenwood Sub 69 kV transformer bus.		OGE		06/01/15			OakGrove 69 kV	Hwy 99 Tap 69 kV	1
	11195	899	regional reliability	Rebuild 11.1 miles with 954 ACSR Cardinal	$4,000,000	SEPC		06/01/15			Holcomb 115 kV	Fletcher 115 kV	1
	50215	766	regional reliability	Add 28.8 Mvar capacitor at Kress 115 kV bus.	$1,166,400	SPS		06/01/15			Kress 115 kV		
	50216	766	regional reliability	Add 28.8 Mvar capacitor at Swisher 115 kV bus.	$1,166,400	SPS		06/01/15			Swisher 115 kV		
	50300	30263	regional reliability	Install 2 Blocks of 7.2 Mvar	$583,200	SPS		06/01/15			JAL 138 kV		
	50301	30264	regional reliability	Install 2 Blocks of 14.4 Mvar	$1,166,400	SPS		06/01/15			Lea Road 138 kV		
	11010	766	regional reliability	Add second Newhart 230/115 kV transformer.	$3,892,500	SPS		06/01/15			Newhart 3 115 kV	Newhart 6 230 kV	2
	11057	798	regional reliability	Reconductor Amarillo - Farmers 115 kV Circuit 2.35 miles with 795 kcmil conductor	$992,000	SPS	06/01/15	06/01/15			Amarillo South Interchange 115 kV	Farmers Sub 115 kV	1
	11060	801	regional reliability	Build new 8.5 mile Lea County Ancell - Gaines 69kV line.	$3,825,000	SPS		06/01/15			Lea County REC-Ancell 69 kV	Lea County REC-Gaines 69 kV	1
	11061	801	regional reliability	Build new 9 mile Lea County TP-91 - Darby 69kV line.	$4,050,000	SPS		06/01/15			Lea County REC-TP91 69 kV	Lea County REC-Darby 69 kV	1
	11062	801	regional reliability	Build new ERF3 substation with new 44MVA 115/69kV transformer.	$11,250,000	SPS		06/01/15			New ERF3 115 kV	Lea County ERF 69 kV	1
	11175	886	regional reliability	Add second Swisher 230/115 kV transformer.	$6,350,000	SPS	06/01/15	6/1/2015			Swisher 230 kV	Swisher 115 kV	2
20004	10186	146	regional reliability	Add 230 kV line from Hobbs to Seminole - 541 MVA.	$8,920,699	SPS	06/01/15	M		02/13/08	Hobbs 230 kV	Seminole 230 kV	1
	10836	694	regional reliability - non OATT	Replace disconnect switches, replace some structures and resag line.	$167,500	SWPA		06/01/15			Asherville 161 kV	Poplar Bluff 161 kV	1
	10576	444	regional reliability - non OATT	Reconductor the 2.2 mi line with 795 ACSR.	$660,000	SWPA		06/01/15			Nixa 69 kV	Nixa DT 69 kV	1
	50285	30272	regional reliability	Install 6 Mvar capacitor at Cole 69 kV bus.	$300,000	WFEC		06/01/15			Cole 69 kV		
	50189	30180	regional reliability	Install 6 Mvar capacitor at Altus Air Force Base 69 kV bus.	$243,000	WFEC	06/01/15	06/01/13			Altus Air Force Base 69 kV		
	50195	30188	regional reliability	Install 18 Mvar capacitor at Erick 138 kV bus.	$729,000	WFEC		06/01/15			Erick 138kV		
	10635	490	regional reliability	Rebuild 5.2 miles of the Bismark to Midland 115 kV line.	$1,950,000	WR	06/01/15	06/01/16			Bismark 115 kV	Midland 115 kV	1
20033	10657	652	regional reliability	Rebuild the Westar portion of the 28.8 mile HEC - Huntsville 115 kV line and reset CTs at HEC.	$12,487,500	WR	06/01/15	06/01/13	NTC-Modify Timing	01/27/09	Hutchinson Energy Center 115 KV	Huntsville 115 kV	1
	10637	492	regional reliability	Tear down / Rebuild 3.55-mile Gill Energy Center - Gill junction portion of the Gill - Oatville 69 kV line. Replace 477 kcmil ACSR conductor with 954 kcmil ACSR and replace terminal equipment. The new rating is the CT limit.	$920,000	WR		M			Gill Energy Center 69 kV	Oatville 69 kV	1
						Year 2016							

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	11171	882	regional reliability	Rebuild/reconductor 11.4 miles of 336 ACSR with 1272 ACSR on the Rock Hill - Carthage 69 kV line. Upgrade Carthage breaker & relay settings & Rock Hill jumpers. Upgrade switches, CT ratios, and relay settings at Rock Hill and Carthage. Remove switches in middle of line.	$11,400,000	AEP		06/01/16			Rock Hill 69 kV	Carthage 69 kV	1
20000	10656	511	regional reliability	Install new 345/161 kV transformer at Osage Creek	$11,000,000	AEP	06/01/16	M		02/13/08	Osage 345 kV	Osage 161 kV	1
20000	10659	511	regional reliability	Install 9 miles of 345 kV line from Shipe Road to East Rogers	$24,500,000	AEP	06/01/16	M		02/13/08	Shipe Road 345 kV	E Rogers 345 kV	1
20000	10660	511	regional reliability	Install 32 miles of 345 kV line from East Rogers to Osage Creek	$65,500,000	AEP	06/01/16	M		02/13/08	E Rogers 345 kV	Osage 345 kV	1
	10898	681	regional reliability	Rebuild 2 miles of 266 ACSR with 795 ACSR and replace Fern Street Switches	$2,000,000	AEP		06/01/16			Broadmoor 69 kV	Fern Street 69 kV	1
	10848	647	zonal - sponsored	Convert 27 mi of 34.5 kV to 69 kV in the Baxter Springs area	$12,375,000	EDE	06/01/16						
	10953	716	regional reliability	Replace Wavetrap	$150,000	GMO		06/01/16			Blue Spring South 161 kV	Prairie Lee kV	1
	10698	549	regional reliability	Reconductor 69 kV Line to 1272 ACSR and replace 600A switch with 1200A switch.	$370,530	GRDA		06/01/16			Maid 69 kV	Pryor Foundry South 69 kV	1
	10699	550	regional reliability	Reconductor 69 kV Line to 1272 ACSR and replace 600A switch with 1200A switch.	$370,530	GRDA		06/01/16			Maid 69 kV	Redden 69 kV	1
	50250	30238	regional reliability	Add one 36 Mvar cap at Riverdale	$1,000,000	NPPD	06/01/16	06/01/16			Riverdale 115 kV		
	50251	30239	zonal - sponsored	Add one 9 Mvar cap at Battle Creek	$500,000	NPPD	06/01/16	06/01/16			Battle Creek 69 kV		
20002	10663	518	regional reliability	Increase rating of HSL East kV to HSL West 69 kV line to 143 MVA. Planned by OGE in 2008.	$250,000	OGE	06/01/16			02/13/08	HSLEast 69 kV	HSLWest 69 kV	1
	10899	682	regional reliability	Rebuild 10.67 miles of line to 477AS33	$5,300,000	OGE		06/01/16			Little River 69 kV	Maud 69 kV	1
	50302	30265	regional reliability - non OATT	Install min. 2 blocks 7.2 Mvar	$583,200	SPS		06/01/16			LE_ERF sub 69 kV		
	11111	842	regional reliability	add new 69 kV Ckt Georgia-Lawrence pk pipe type cable CKT 2	$5,166,960	SPS	06/01/16	06/01/11			Lawrence pk 69 kV	Georgia S 69 kV	2
	11112	843	regional reliability	add new 69 kV Ckt SONCY-Lawrence pk 2 pipe type cable CKT 2	$6,571,440	SPS	06/01/16	06/01/16			Lawrence Pk 2 69 kV	Soncy 69 kV	2
	11113	844	regional reliability	Upgrade 9.9 miles of 69 kV between Mustang to Sunshine Canyon from 4/0 to 795; new rating 91/114	$3,341,000	WFEC		06/01/16			Mustang 69kV	Sunshine Canyon 69kV	1
	11117	847	regional reliability	Upgrade Wakita to Nash, 1/0 to 336.4 ACSR	$6,705,000	WFEC		06/01/16			Nash 69 kV	Wakita 69 kV	1
	10865	659	regional reliability	Convert 11 mile Reeding - Cashion 69 kV line to 138 kV.	$3,712,500	WFEC	06/01/16	06/01/14			Reeding 138 kV	Cashion 138 kV	1
	10869	663	regional reliability	Tear down and rebuild TEC - Hook Jct. - County Line 115 kV.	$641,250	WR		06/01/16			Tecumseh Energy Center 115 kV	Hook Jct 115 kV	1
						Year 2017							
	50256	30243	regional reliability	Install 12 Mvar cap bank at Bloomburg 69 kV.	$500,000	AEP		06/01/17			Bloomburg 69 kV		
	11157	877	regional reliability	Rebuild 13.9 miles of 4/0 ACSR with 795 ACSR and reset Clinton City relay.	$13,900,000	AEP		06/01/17			Clinton City 69 kV	Thomas Tap 69 kV	1
	11158	878	regional reliability	Reconductor 2.68 miles of 477 ACSR 69 kV line with 1272 ACSR and raise CT ratio and relay settings.	$2,700,000	AEP		06/01/17			North Mineola 69 kV	Mineola 69 kV	1
	10649	504	regional reliability	Rebuild 4.7 mile Brown Lee- North Market 69 kV line of 2-203 ACSR & 666 ACSR with 1272 ACSR & raise CT ratio & relay settings..	$4,700,000	AEP		06/01/17			Brown Lee 69 kV	North Market 69 kV	1
	10647	502	regional reliability	Reconductor 3.25 miles Northwest Henderson-Poynter 69 kV line with 1272 ACSR.	$3,220,000	AEP		06/01/17			Northwest Henderson 69 kV	Poynter 69 kV	1
20036	10571	440	regional reliability	Reconductor 7.55 mile Diamond Jct. - Sarcoxie Southwest 69 kV line from 1/0 Cu to 336 ACSR.	$2,274,000	EDE		06/01/17	NTC-Modify Timing	01/27/09	SUB 131 - Diamond Junction 69 kV	SUB 362 - Sarcoxie Southwest 69 kV	1
	10891	677	regional reliability	Tear down the Riverton to Joplin 59 69 kV line, rebuilding the line to 161 kV from Stateline to outside Joplin 59 sub. Tear down and rebuild Joplin 59 to Gateway to Pilsbury to Reinmiller, converting those 69 kV lines to 161 kV. Tap the 161 kV line between Joplin 59 and Gateway at Joplin 422.	$25,000,000	EDE	06/01/17	06/01/18			SUB 439 - Stateline 161 kV	Joplin 59 161 kV	1
	10892	677	regional reliability			EDE	06/01/17	06/01/18			Joplin 59 161 kV	Gateway 161 kV	1
	10893	677	regional reliability			EDE	06/01/17	06/01/18			Gateway 161 kV	Pilsbury 161 kV	1
	10894	677	regional reliability			EDE	06/01/17	06/01/18			Pilsbury 161 kV	Reinmiller 161 kV	1
20036	10259	203	regional reliability	Reconductor 3.5 mile Atlas Jct. - Carthage Northwest 69 kV line from 4/0 ACSR to 336 ACSR for 65 MVA Rate B.	$1,277,935	EDE		06/01/17	NTC-Modify Timing	01/27/09	SUB 109 - Atlas Junction 69 kV	SUB 108 - Carthage Northwest 69 kV	1
	10716	565	regional reliability	Reconductor with 795ACSR.	$450,000	GMO	06/01/17	06/01/19			Clinton 69 kV	Clinton Plant 69 kV	1
	10904	687	regional reliability	Replace wavetraps at Longview and Western Electric	$50,000	GMO		06/01/17			Longview 161 kV	Western Electric 161 kV	1
	50214	30207	regional reliability	18 Mvar 115 KV CAP BANK AT COZAD	$1,000,000	NPPD	06/01/17	06/01/17			Cozad 115 kV		
20017	50168	30160	transmission service	Convert Ft. Smith 161 kV to 1-1/2 breaker design and install 3rd 500-161 kV transformer bank.	$11,000,000	OGE	06/01/17	M		01/16/09	Fort Smith 500 kV	Fort Smith 161 kV	5
20017	50172	30164	transmission service	Upgrade CT	$100,000	OGE	06/01/17	M		01/16/09	VBI 161 kV	VBI North 161 kV	1
	11071	810	regional reliability	Build new 100 mile 345 kV line from OGE Anadarko to Oklahoma/Texas border towards SPS's Reactor station on Woodward-Tuco 345 kV line.	$120,000,000	OGE		06/01/17			Stateline 345 kV	Anadarko (Gracemont) 345 kV	1
	11140	863	regional reliability	Increase line clearances to allow the use of a higher conductor rating.	$146,000	OPPD		06/01/17			SUB 907 69 kV	SUB 911 69 kV	1
	50220	30216	regional reliability	Install 50 Mvar capacitor bank at Wheeler min. 2 Blocks 25Mvar	$4,050,000	SPS		06/01/17			Wheeler 230 kV		
	50303	30266	regional reliability	Install additional BLOCK 14.4 Mvar	$583,200	SPS		06/01/17			Bailey Co 69 kV		
	11004	761	regional reliability	Reconductor 7.78 miles with 795 kcmil conductor.	$3,375,000	SPS	06/01/17	06/01/17			Chaves County Interchange 115 kV	Samson Sub 115 kV	1
	11005	762	regional reliability	Reconductor 3.70 miles with 795 kcmil conductor.	$3,375,000	SPS	06/01/17	06/01/17			Chaves County Interchange 115 kV	Urton Sub 115 kV	1
	11069	807	regional reliability	Build new 10 mile 345 kV line from SPS's Reactor station on Woodward-Tuco 345 kV line to Oklahoma/Texas border towards OGE Anadarko.	$16,425,000	SPS	06/01/17	06/01/17			Stateline 345 kV	Anadarko (Gracemont) 345 kV	1
	11070	808	regional reliability	Build new 115 mile 345 kV line from Potter to Stateline.	$134,325,000	SPS	06/01/17	06/01/17			Potter County Interchange 345 kV	Stateline 345 kV	1
	11006	763	regional reliability	Add second 115/69 kV transformer at Gray County substation.	$1,890,000	SPS	06/01/17	06/01/17			Gray County Interchange 115 kV	Gray County Interchange 69 kV	2
	11127	856	regional reliability	Convert 69 kava load to 115 kV and build 5 mile line	2812500	SPS		06/01/17			NE Hereford 115 kV	Centre 115 Kv	1
	11100	833	regional reliability	Add 2nd transformer 115/69 kV 84/96 MVA CKT 2	$1,890,000	SPS	06/01/17	06/01/17			NE Hereford 115 kV	NE Hereford 69 kV	2
	50146	30140	regional reliability - non OATT	Install 3.6 Mvar capacitor at China.	$145,800	SWPA		06/01/17			China 69 kV		
	11205	909	regional reliability	Reconductor 4.0 miles with 556 kcmil conductor.	$2,250,000	WFEC		06/01/17			Oklahoma University SW 69 kV	Cole 69 kV	1
	10867	661	regional reliability	Tear down and rebuild 2.52-mile County Line-Hook Jct 115 kV line, 1192 ACSR.	$1,063,125	WR		06/01/17			Hook JCT 115 KV	County Line 3 115 kV	1
	10998	756	regional reliability	Tap Lawrence Hill-Swissvale 230 kV line near Baldwin Creek substation and install Baldwin Creek 230/115 kV transformer	$6,930,000	WR		06/01/17			Baldwin Creek 230 kV	Baldwin Creek 115 kV	1
						Year 2018							
	50193	30184	regional reliability	Install 6 Mvar capacitor for a total of 12 Mvar at South Nashville.	$600,000	AEP		06/01/18			South Nashville 138 kV		
	10616	479	regional reliability	Rebuild 12.63 mi of the Georgia Pacific-Keatchie 138 kV 795 ACSR line with 1272 ACSR.	$12,630,000	AEP		06/01/18			Georgia-Pacific 138 kV	Keatchie REC 138 kV	1
	10615	478	regional reliability	Rebuild 0.27 miles Forbing Road to South Shreveport 69 kV to 1272 ACSR (next limit is 500 Cu bus & jumpers).	$350,000	AEP		06/01/18			Forbing Tap 69 kV	South Shreveport 69 kV	1
	10654	509	regional reliability	Convert the 506952 Centerton 69-12.5 kV station to 161-12.5 kV. Disconnect Centerton station from the 69 kV line and connect to the 506929 East Centerton to 506960 Bentonville Hwy 279 161 kV line 2.0 miles west of 506929 East Centerton station.	$2,904,000	AEP		06/01/18			Centerton 161 kV		1
	50136	30130	regional reliability	Install 30 MVAR capacitor at Twin Oaks Substation	$750,000	CUS	06/01/18	06/01/18			Twin Oaks 69 kV		
	11076	814	zonal - sponsored	Rebuild James River to South Highway 69 kV	$1,282,500	CUS	06/01/18	M			James River 69 kV	South Highway 65 69 kV	1
	11077	815	zonal - sponsored	Rebuild South Highway to Sunset 69 kV	$641,250	CUS	06/01/18	M			Sunset 69 kV	South Highway 65 69 kV	1
	10905	688	regional reliability	Replace Odessa 161/69kV transformer with new 100/110MVA	$2,000,000	GMO		06/01/18			Odessa 161kV	Odessa 69kV	1
	10873	667	regional reliability	Replace 600A switch with 1200A switch	$112,500	GRDA		06/01/18			Pryor Foundry South 69 kV	CPP Transformer #2 69 kV	1
	11120	850	regional reliability	Upgrade the 800 amp CT in Penn Sub to 1200 amp	$25,000	OGE		06/01/18			Kentucky Tap 69 kV	Pennsylvania 69 kV	1
	11066	804	regional reliability	Add 3rd transformer at TUCO 230/115 250 MVA CKT 3	$13,500,000	SPS		06/01/18			Tuco Interchange 230 kV	Tuco Interchange 115 kV	3
	11067	805	regional reliability	Add 2nd transformer at Bowers 115/69 kV CKT 2	$1,890,000	SPS		06/01/18			Bowers Interchange 115 kV	Bowers Interchange 69 kV	2
	11124	854	regional reliability	Add new 345 kV line Tuco - Jones Ckt 1 29.66 miles	$33,367,500	SPS	06/01/18	06/01/18			Tuco 345 kV	Jones 345 kV	1
	11125	854	regional reliability	Add new 345-230 kV 559 MVA CKT 1	$22,150,000	SPS		06/01/18			Jones 345 kV	Jones 230 kV	1
	11105	837	regional reliability	Add new 115 kV Ckt Lamb Co to Lea County Littlefield	$2,925,000	SPS		06/01/18			Lamb Co 115 kV	LC-Little 115 kV	1
	11173	884	regional reliability	Add 2nd transformer Eddy Co 230-115 kV CKT 2	$8,352,500	SPS	06/01/18	6/1/2018			Eddy 230 kV	Eddy 115 KV	2
	11174	885	regional reliability	Add 2nd transformer Carlise 230-115 kV CKT 2	$8,352,500	SPS	06/01/18	6/1/2018			Carlise 230 kV	Carlise 115 kV	2
	10896	679	regional reliability - non OATT	Replace Poplar Bluff 2nd transformer with larger transformer, 70/70 MVA unit.	$2,250,000	SWPA		06/01/18			Poplar Bluff 69 kV	Poplar Bluff 161 kV	2
	50304	30267	zonal - sponsored	add one stage of 10 Mvar to existing 10 Mvar	$432,000	WR	06/01/18	M			Allen 69 kV		
	50305	30268	zonal - sponsored	add one stage of 10 Mvar to existing 10 Mvar	$432,000	WR	06/01/18	M			Athens 69 kV		
	10563	433	regional reliability	Reset ct's. New Rate A:108 B:108	$150,000	WR		M			Yost 69 kV	Moundridge 69 kV	1
	11083	820	regional reliability	Tear down and rebuild 17th & Fairlawn - Indian Hills 115kV Ckt 1	$1,687,500	WR		06/01/18			17th & Fairlawn 115 kV	Indian Hills 115 kV	1
						Year 2019							
	10619	481	regional reliability	Rebuild and reconductor 4.0 miles of 4/0 ACSR 69 kV to 1590 ACSR 161 kV from converting North Huntington to Midland REC to 161 kV. Add 161 kV terminal at North Huntington.	$6,000,000	AEP		06/01/19			North Huntington 161 kV	Midland REC 161 kV	1
	10620	481	regional reliability	Rebuild and reconductor Midland REC-Midland from 69 kV 4/0 ACSR to 161 kV 1590 ACSR.	$1,500,000	AEP		06/01/19			Midland REC 161 kV	Midland 161 kV	1
	10621	481	regional reliability	Add 161/69 kV autotransformer at Midland.	$2,500,000	AEP		06/01/19			Midland 161 kV	Midland 69 kV	1
	10624	481	regional reliability	Build Bonanza-Midland 1590 ACSR 161 kV line. Old Midland-Excelsior section to be converted from 69 kV to 161 kV. Add 4-161 kV breakers at Bonanza.	$17,000,000	AEP		06/01/19			Bonanza Tap 161 kV	Midland 161 kV	1
	11158	879	regional reliability	Rebuild 9.0 mile Prattville-Bluebell 138 kV line from 795 ACSR to 1590 ACSR. New summer ratings 287/287 limited by breaker, switches, CTs, wave trap.	$9,000,000	AEP		06/01/19			Bluebell 138 kV	Prattville 138 kV	1
	10646	501	regional reliability	Replace 600 A breaker with 1200A at Evenside 69 kV.	$200,000	AEP		06/01/19			Evenside 69 kV	NW Henderson 69 kV	1
	10609	473	regional reliability	Reconductor 69kV line from 636 ACSR to 762.8 ACSS/TW	$979,000	CUS	06/01/19	06/01/19			James River 69 kV	Twin Oaks 69 kV	1

SPP Boad of Directors Approved Appendix A projects January 26, 2010

	10877	671	regional reliability	Increase CT ratio at both Chickasaw and Ardmore. Also possibly change out relay	$450,000	OGE		06/01/19			Ardmore 69 kV	Chickasaw 69 kV	1
	10999	30212	regional reliability	Replace Jones Tap bus 1200A switch with 2000A switch.	$250,000	OGE		06/01/19			Jones Tap 138 kV	Bryant 138 kV	1
	11119	849	regional reliability	Upgrade the existing 600 amp 69 kV switches in Kentucky Sub to 1200 amp	$60,000	OGE		06/01/19			Kentucky 69 kV	Kentucky Tap 69 kV	1
	11207	910	regional reliability	Replace wavetrap	$225,000	OGE		06/01/19			Bryant 138 kV	Memorial 138 kV	1
	10906	689	regional reliability	Replace South Waverly 161/69kV transformer with larger 30/33MVA model; interim mitigation is to move 20% of load off S Waverly 161kV bus starting in 2010	$2,000,000	KCPL		06/01/19			South Waverly 161kV	South Waverly 69kV	1
	11136	859	regional reliability	Reconductor Hawthorn - Birmingham 161kV	$1,670,625	KCPL		06/01/19			Birmingham 161kV	Hawthorn 161kV	1
	10994	30211	regional reliability	Replace Medicine Lodge 138/115 kV transformer with a larger 147/170 MVA transformer	$3,825,000	MKEC		06/01/19			Medicine Lodge 138 kV	Medicine Lodge 115 kV	1
	10991	30208	regional reliability	Rebuild MKEC portion of the Clearwater-Milan tap 115 kV with bundled 1192.5 kcmil ACSR conductor (Bunting)	$3,150,000	MKEC		06/01/19			Clearwater 138 kV	Milan Tap 138 kV	1
	10993	30210	regional reliability	Replace Wave Trap at Harper Substation.	$225,000	MKEC		06/01/19			Harper 138 kV	Milan Tap 138 kV	
	10990	753	regional reliability	Reconductor and upgrade terminal equipment to effect higher rating by 2019. 240 MVA Normal Continuous Rating. 240 MVA 4-Hour Emergency Rating.	$6,000,000	NPPD	06/01/19	06/01/19			Beatrice 115 kV	Harbine 115 kV	1
	50254	30241	regional reliability	Install 21.6 Mvar capacitor bank	$2,213,000	OPPD		06/01/19			Neb City U Sub 903 69 kV		
	50306	30269	regional reliability	Install 2 Blocks of 14.4 Mvar	$1,166,400	SPS		06/01/19			Lamb Co 115 kV		
	50307	30270	regional reliability	Install min. 2 blocks 14.4 Mvar	$1,166,400	SPS		06/01/19			Deaf Smith 115 kV		
20031	10195	151	regional reliability	Add third Tuco 115/69 kV autotransformer with 84/84 MVA rating.	$1,260,000	SPS		06/01/19		01/27/09	Tuco 69 kV	Tuco 115 kV	1
20031	10197	153	regional reliability	Add third Potash Junction interchange 115/69 kV transformer.	$600,000	SPS		06/01/19		01/27/09	Potash Junc 69 kV	Potash Junc 115 kV	1
	11092	825	regional reliability	Reconductor 0.45 miles 69 kV from 4/0 to 397.5 ACSR	$225,000	SPS		06/01/19			Artesia 69 kV	CV-Artesia 69 kV	1
	11094	827	regional reliability	Reconductor 8.34 miles 115 kV from 397.5 to 750 ACSR	$3,518,438	SPS		06/01/19			Cherry 115 kV	Northwest 115 kV	1
	11099	832	regional reliability	Add 2nd transformer 115/69 kV 84/96 MVA CKT 2	$1,890,000	SPS		06/01/19			Northwest 69 kV	Northwest 115 kV	2
	11106	838	regional reliability	Add new 115 kV Ckt Hockley Co-E Levelland Co	$3,037,500	SPS		06/01/19			Hockley Co 115 kV	E Levelland 115 Kv	1
	11126	855	regional reliability	convert 69 kV load onto 115 kV	85375	SPS		06/01/19			Stanton 69 kV	Stanton 69 kV	1
	11198	901	regional reliability	Replace NICHOLS Line Trap with 1200 Amp B unit 230 kV	$450,000	SPS		06/01/19			Nichols Station 230 kV	Amarillo South Interchange 230 kV	1
	10860	655	regional reliability - non OATT	Replace Springfield transformer #1 three winding transformer with 70 MVA auto transformer.	$825,000	SWPA		06/01/19			Springfield 161 kV	Springfield 69 kV	1
	11193	898	zonal - sponsored	convert County Line - Arnold to 115 kV. Valley Falls sub converted to 115	$8,521,875	WR	06/01/19	M			County Line 115 kV	Valley Falls 115 kV	1
	11194	898	zonal - sponsored	convert County Line - Arnold to 115 kV. Valley Falls sub converted to 115	$9,534,375	WR	06/01/19	M			Arnold 115 kV	Valley Falls 115 kV	1
	10992	30209	regional reliability	Rebuild Westar portion of the Clearwater-Milan tap 115 kV with bundled 1192.5 kcmil ACSR conductor (Bunting)	$3,431,250	WR		06/01/19			Clearwater 138 kV	Milan Tap 138 kV	1
						Withdraw							
20000	10444	347		Reconductor with 2.7 miles 477 ACSR 69 kV Woodlawn-Baldwin. Reset relays.	$2,000,000	AEP	06/01/11	D	NTC-Withdraw	02/13/08	Baldwin 69 kV	Woodlawn 69 kV	1
20027	10614	477		Reconductor 6.9 miles with 477 ACSR 69 kV from Baldwin - Karnack Tap.	$6,900,000	AEP	06/01/13	D	NTC-Withdraw	01/27/09	Baldwin 69 kV	Karnack Tap 69 kV	1
20016	10442	345		Replace 69 kV switch at Magnola tap for new emergency limit 85 MVA.	$125,000	AEP	06/01/10	D	NTC-Withdraw	01/16/09	Quitman-Magnolia 69 kV	Forest Hills REC 69 kV	1
20011	10572	441		Reconductor 69kV line from 636 ACSR to 762.8 ACSS/TW	$805,000	CUS	06/01/12	D	NTC-Withdraw	02/13/08	Kickapoo 69 kV	Sunset 69 kV	1
20034	50182	30174		Install 5 Mvar capacitor at Craig 69 kV bus.	$350,000	GMO		D	NTC-Withdraw	01/27/09	Craig 69 kV		
20034	50082	30076		Install 12 Mvar capacitor at Warsaw 69 kV bus.	$409,900	GMO		D	NTC-Withdraw	01/27/09	Warsaw 69 kV		
20028	50185	30177		Add additional 7.2 Mvar capacitor at Tahlequah West, for a 28.8 Mvar total.	$291,600	GRDA		D	NTC-Withdraw	1/27/2009	Tahlequah West 69 kV		
20009	10492	379		New Hillsdale-Cedar Niles 161 kV Line and Cedar Niles ring bus	$5,418,700	KCPL	06/01/15	D	NTC-Withdraw	02/13/08	Hillsdale 161 kV	Cedar Niles 161 kV	1
20002	10515	397		Convert 7 mile Mustang -Yukon 69 kV line to 138 kV.	$6,850,000	OGE	06/01/12	D	NTC-Withdraw	02/13/08	Mustang 138 kV	Yukon 138 kV	1
20002	10516	397		Convert 3 mile Yukon - Cimarron 69 kV line to 138 kV.	$3,500,000	OGE	06/01/12	D	NTC-Withdraw	02/13/08	Yukon 138 kV	Cimarron 138 kV	1
20003	50100	30094		Install 6 Mvar capacitor at Mustang 69 kV.	$162,000	WFEC		D	NTC-Withdraw	02/13/08	Mustang 69 kV		
20033	10811	623		Rebuild the 14.63 miles of 69 kV line from Timber Junction - Winfield.	$7,415,000	WR	12/31/10	D	NTC-Withdraw	01/27/09	Timber Junction 69 kV	City Of Winfield 69 Kv	1
20033	10812	624		Build new 8.76 mile Fort Junction - West Junction City 115 kV line that follows the path of the JEC - Summit 345 kV line. Remove old double circuit and West Junction City Junction (East) - West Junction City 115 kV line.	$4,927,500	WR	06/01/11	D	NTC-Withdraw	01/27/09	Fort Junction Switching Station 115 kV	West Junction City 115 kV	1
20006	10536	410		Rebuild Ark Valley-Tower 33 115 kV	$2,306,250	WR		D	NTC-Withdraw	02/13/08	Ark Valley 115 kV	Tower 33 115 kV	1
20033	10640	495		Rebuild the 5.49 mile Lawrence Hill to Mockingbird Hill 115 kV line.	$2,377,448	WR		D	NTC-Withdraw	01/27/09	Lawrence Hill 115kV	Mockingbird Hill 115 kV	1
20033	10218	169		Uprate CT ratio on Chapman - Clay Center 115 kV line.	$10,000	WR	06/01/17	D	NTC-Withdraw	01/27/09	Chapman 115 kV	Clay Center Junction 115 KV	1

Appendix B – Empire District STEP Projects

	SPP Board Of Directors Approved Transmission Expansion Projects 1-26-10 - Empire District Electric Projects Only				
Project Type	**Project Description/Comments**	**Cost Estimate**	**From Bus Name**	**To Bus Name**	**Circuit**
		YEAR 2010			
Zonal Reliability	Install (3) 22 Mvar capacitor banks for a total of 66 Mvar at Riverside Sub #438	$2,600,000	SUB 438 - Riverside 161 kV		
regional reliability	Change CT setting on Breaker #6973 at Baxter #271 to 800/5 ratio	$50,000	SUB 404 - Hockerville 69 kV	SUB 271 - Baxter Springs West 69 kV	1
regional reliability	Change CT ratio on breaker #6936 at Aurora Substation 124	$5,000	SUB 124 - Aurora H.T. 69 kV	SUB 152 - Monett H.T. 69 kV	1
transmission service	Rebuild 1.7 mile Neosho South Jct. - Neosho SPA 161 kV from 336 ACSR to 795 ACSR and replace terminal equipment	$1,215,000	SUB 184 - Neosho South Junction 161 kV	Neosho (SWPA) 161 kV	1
regional reliability	Replace 600 amp disconnect switches with a minimum 1,2300 amp units and replace leads on Breaker #6965 at Sub #64 and #6932 at Sub #145	$55,000	SUB 145 - Joplin West 7th 69 kV	Sub 64 - Joplin 10th ST 69 kv	1
		YEAR 2011			
transmission service	Replace auto transformer at ORONOGO 110 with 150 MVA rated auto transformer due to increased generation available	$4,000,000	ORO110 5 161 kV	ORO110 2 69 kV	1
transmission service	Reconductor 11.9 miles of Oronogo Jct. to Riverton 161 kV Ckt. 1 from 556 ACSR to 795 ACSR, change CT settings @ Oronogo, and replace wavetrap.	$5,750,000	Sub 110 - Oronogo Jct.	Sub 167 - Riverton	1
		YEAR 2012			
regional reliability	Reconductor 8.92 miles Nichols-Sedalis 69 kV with 556 ACSR and upgrade CTs	$3,520,000	SUB 170 - Nichols St 69 kV	Sedalia 69 kV	1
regional reliability	Replace jumpers on breaker #6950 at Blackhawk Junction with 556 ACSR for rates 73/89 MVA	$50,000	Jamesville 69 kV	SUB 415 - Blackhawk Junction 69 kV	1
		YEAR 2013			
		NONE			
		YEAR 2014			
regional reliability	Replace jumpers	$100,000	SUB 403 - Jasper West Tap 69 kV	SUB 249 - Boston East 69 kV	1
regional reliability	Raise structures on Diamond Jct. - Sarcoxie Southwest 69 kV line to achieve a new rating B of 44 MVA	$50,000	SUB 131 - Diamond Junction 69 kV	SUB 362 - Sarcoxie Southwest 69 kV	1
regional reliability	Replace switch on transfer bus at Sub #167 for Rate B = 91 MVA	$75,000	Sub 167 - Riverton 69 kV	SUB 278 - Galena Northeast 69 kV	1
regional reliability	Reconductor 1.0 Mile of 4/0 ACSR with 336 ACSR for 65 MVA Rate B	$400,000	SUB 436 - Webb City Cardinal 69 kV	SUB 110 - Oronogo Junction 69 kV	1
		YEAR 2015			
regional reliability	Build new 9.2 mile Substation 383 - Monett 5 161 kV line	$7,389,319	SUB 383 - Monett 161 kV	South Monett 161 kV	1
regional reliability	Install 3-winding transformer connecting new 161 kv line to Monett City South 69 kV	$8,000,000	South Monett 161 kV	SUB 376 - Monett City South 69 kV	1
regional reliability	Reconductor 1.2 mi with 336 ACSR	$275,000	Monett City South Jct. 69 kV	Monett City East 69 kV	1
		YEAR 2016			
zonal - sponsored	Convert 27 mi of 34.5 kV to 69 kV in the Baxter Springs area	$12,375,000			

	SPP Board Of Directors Approved Transmission Expansion Projects 1-26-10 - Empire District Electric Projects Only (continued)				
		YEAR 2017			
regional reliability	Reconductor 7.55 miles Diamond-Jct - Sarcoxie Southwest 69 kV lines from 1/0 Cu to 336 ACSR	$2,274,000	SUB 131 - Diamond Junction 69 kV	SUB 362 - Sarcoxie Southwest 69 kV	1
regional reliability	Tear down the Riverton to Joplin 59 69 kV line, rebuilding the line to 161 kV from Stateline to outside Joplin sub. Tear down and rebuild Joplin 59 to Gateway to Pillsbury to Reinmiller, converting those 69 kV lines to 161 kV. Tap the 161 kV line between Joplin 59 and Gateway at Joplin 422	$25,000,000	SUB 439 - Stateline 161 kV	Joplin 59 161 kV	1
regional reliability			Joplin 59 161 kV	Gateway 161 kV	1
regional reliability			Gateway 161 kV	Pillsbury 161 kV	1
regional reliability			Pillsbury 161 kV	Reinmiller 161 kV	1
regional reliability	Reconductor 3.5 miles Atlas Jct - Carthage Northwest 69 kV lines from 4/0 ACSR for 65 MVA Rate B	$1,277,935	SUB 109 - Atlas Junction 69 kV	SUB 108 - Carthage Northwest 69 kV	1
		YEAR 2018			
		NONE			
		YEAR 2019			
		NONE			

Appendix C

Empire 2010-2014 Transmission and Distribution Construction Budget **Highly Confidential in its Entirety**

****Highly Confidential in its Entirety****

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Abbreviations

ACFB – Atmospheric Circulating Fluidized Bed
AECI – Associated Electric Cooperative
AEP – American Electric Power
AFUDC – Allowance for Funds Used During Construction
AMI – Advanced Metering Infrastructure
AQCS – Air Quality Control Systems
AWEA – American Wind Energy Association
BNSF – Burlington Northern Santa Fe Railroad
Btu – British Thermal Unit
CAES – Compressed Air Energy Storage
CAIR – Clean Air Interstate Rule
CAMR – Clean Air Mercury Rule
CC – Combined cycle
CCS – Carbon capture and sequestration
CFB – Circulating Fluidized Bed
CO_2 – Carbon dioxide
CSP – Concentrating solar power
CT – Combustion turbine
DOE – Department of Energy
EIA – Energy Information Administration
EPA – U.S. Environmental Protection Agency
ESBWR – Economic simplified boiling-water reactor
FERC – Federal Energy Regulatory Commission
GDP – Gross Domestic Product
Hg – Mercury
HRSG – Heat recovery steam generator
IGCC – Integrated Gasification Combined Cycle
IRP – Integrated Resource Plan or integrated resource planning
ITP – Integrated Transmission Planning
KCP&L – Kansas City Power & Light
kV – kilovolt
kW – kilowatt
kWh – kilowatthour
MCSP – Missouri Carbon Sequestration Project
MMBtu- Millions of British Thermal Units
MPSC – Missouri Public Service Commission
MW – Megawatt
MWh – Megawatthour
NO_x – Nitrous oxides
NRC – U.S. Nuclear Regulatory Commission
NYMEX – New York Mercantile Exchange
NSI – Net System Input
O&M – Operating and Maintenance
OG&E – Oklahoma Gas & Electric

OMS – Outage Management System
PPA – Power Purchase Agreement
PRB – Power River Basin
PV - Photovoltaics
PVRR – Present Value of Revenue Requirements
REC – Renewable Energy Credit
RMP – Risk Management Policy
RPS – Renewable Portfolio Standard
SCR – Selective catalytic reduction
SLCC – State Line Combined Cycle
SMR – Small modular reactor
SO_2 – Sulfur dioxide
SPP – Southwest Power Pool
SPP RTO – Southwest Power Pool Regional Transmission Organization
STEP – SPP Transmission Expansion Plan
VOC – Volatile Organic Compounds
WTI – West Texas Intermediate