2012 Integrated Resource Plan Annual Update Report

The Empire District Electric Company

March 2012

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The Empire District Electric Company (Empire)
2012 Integrated Resource Planning (IRP) Update Report

1.0 Introduction

The purpose of the annual update is to ensure that members of the Missouri stakeholder group have the opportunity to provide input and to stay informed regarding the changing conditions since the last filed triennial compliance (IRP) filing or annual update filing. This includes updates regarding:

1. Utility's current preferred resource plan;
2. Status of the identified critical uncertain factors;
3. Utility's progress in implementing the resource acquisition strategy;
4. Analyses and conclusions regarding any special contemporary issues that may have been identified pursuant to 4 CSR 240-22.080(4);
5. Resolution of any deficiencies or concerns pursuant to 4 CSR 240-22.080(16); and
6. Changing conditions generally.

Empire's most recent Missouri triennial compliance filing was made in File No. EO-2011-0066 on September 3, 2010 (September 2010 IRP). This filing was made to comply with the requirements of 4 CSR 240-22 (Rule or IRP Rule) based on Empire's interpretations of the Rule that was in place at that time. Empire requested variances and clarifications from the Missouri Public Service Commission (MPSC) for those instances in which the filing was at variance with the Rule. The MPSC issued an order granting Empire's application for variance in June 2010 (EE-2010-0246). In October 2010 Empire met with stakeholders to present and answer questions about the September 2010 IRP filing. On or about January 3, 2011 some of the stakeholders filed comments concerning Empire's 2010 triennial compliance filing. After several post-filing IRP discussions, a non-unanimous stipulation and agreement was reached and filed with the Commission on April 1, 2011. The Commission issued an Order approving the non-unanimous stipulation and agreement and accepting the integrated resource plan on April 27, 2011. This agreement created the Empire IRP Stakeholder Advisory Group which has been meeting, and will continue to meet quarterly until Empire's next triennial filing. A Commission Order closing File No. EO-2011-0066 was issued on June 7, 2011.

Since Empire's last triennial filing, the IRP rules in Missouri have undergone a significant revision. In fact, the annual update and the special contemporary issues are new requirements introduced in the revised Chapter 22 IRP Rule. As a result, this is Empire's first annual update report and the first set of Commission approved special contemporary issues that Empire has been required to address. The Commission Order establishing the special contemporary issues list for Empire was filed on October 19, 2011 in File No. EO-2012-0040.

On September 29, 2011 Empire filed an application for variance in File No. EE-2012-0095 concerning some of the annual update requirements in 4 CSR 240-22.080. An agreement among the stakeholders was filed on December 5, 2011, and the Commission issued an Order approving the agreement on December 21, 2011. This File was closed on January 6, 2012.

In addition to the periodic IRP analysis, Empire has an ongoing internal planning process. Empire creates a five year business plan on an annual basis. Most of the updates in this report will be based on Empire's most recent approved five year business plan which is internally referred to as the five year budget. Empire is in the early stages of developing its next IRP triennial compliance filing for Missouri. Following some input from the Empire IRP Stakeholder Advisory Group, the following IRP work is under way: (1) the load forecasting methodology has been modified to comply with the revised IRP rules. A preliminary load forecast has been developed with the new methodology by Empire with assistance from Empire's consultant Itron. (2) The update of the technical potential study for the demand-side analysis is also in progress. This study is being conducted by Empire's demand-side consultant Applied Energy Group (AEG). For those instances when this update report utilizes some of the preliminary IRP data it will be noted. Empire's next triennial compliance filing is scheduled for April 1, 2013.

1.1 Report Contents

This report is organized into the following sections:

- Section 1 is the introduction

- Section 2 will provide an update on the status of each of the critical uncertain factors that were identified in Empire's most recent triennial compliance filing.
    - Section 2.1 environmental costs update
    - Section 2.2 market and fuel prices update
    - Section 2.3 load forecast update
    - Section 2.4 capital costs and interest rates update

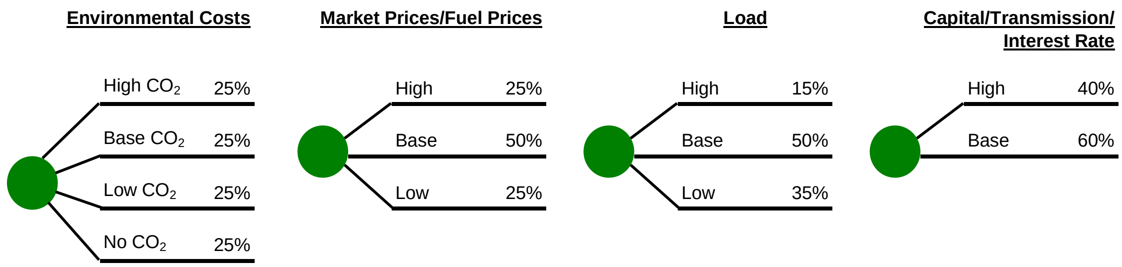
- Section 3 will provide an update on the resource acquisition strategy that was described in Empire's most recent triennial compliance filing.
    - Section 3.1 demand-side management (DSM)
    - Section 3.2 Asbury air-quality control system (AQCS) project
    - Section 3.3 Riverton coal units
    - Section 3.4 Riverton 12 combustion turbine (CT) conversion to combined cycle (CC)

- Section 4 will provide an update of the preferred plan that was identified in Empire's most recent triennial compliance filing.
    - Section 4.1 Riverton combined cycle project preferred plan update
    - Section 4.2 Riverton coal units preferred plan update
    - Section 4.3 Load and capability balance report update

- Section 5 will address the Empire special contemporary issues that were established by Commission Order in File No. EO-2012-0040.
  - Section 5.1 impacts of the May 22, 2011 Joplin tornado
    - Analyze and document how Empire's load-forecast will account for the impact of tornado damage in its service territory. Analyze and document how on-going recovery efforts impact Empire's capacity balance and participation in DSM programs. Analyze and document how these changes impact the preferred resource plan or contingency plans.
  - Section 5.2 loss of significant load
    - Investigate and document the impacts on Empire's preferred resource plan and contingency plans of a loss of significant load for the short term and potentially for the long term that may be the result of a prolonged double dip recession or a large customer or group of customers no longer taking service from Empire.
  - Section 5.3 impacts of newly proposed aggressive environmental regulations
    - Investigate and document the updated impacts of newly proposed aggressive environmental regulations on Empire's preferred resource plan and contingency plans.
  - Section 5.4 potential or proposed changes in state or federal environmental or renewable energy standards
    - Analyze potential or proposed changes in state or federal environmental or renewable energy standards and report how those changes would affect Empire's plans for compliance with those standards.
  - Section 5.5 current Renewable Energy Standards law compared to a portfolio comprised solely of existing resources with no additional renewable resources.
    - Analyze the levelized cost of energy needed to comply with the current Renewable Energy Standards law compared to the cost of energy resulting from a portfolio comprised solely of existing resources with no additional renewable resources.
  - Section 5.6 impact of every state or federal fuel source subsidy
    - Disclose and discuss the amount and impact of every state or federal subsidy Empire expects to receive with regard to any or all fuel sources it intends to use during the IRP study period.

2.0 Status of the Identified Critical Uncertain Factors

In the most recent triennial filing (September 2010 IRP filing, most recent IRP, last IRP or recent IRP) Empire identified the following critical uncertain factors: (1) environmental costs; (2) market prices/fuel prices; (3) load; and (4) capital/transmission/interest rates. This section will address changes in these factors since the last IRP.



2.1 Environmental Costs Update

In the September 2010 IRP filing, the environmental analysis assumed three levels of future CO_2 (carbon) costs within a potential cap and trade future and one case with no future carbon costs. The base case assumed that a cap and trade system for carbon would be in place by year 2015. Empire's current five year business plan which covers the period 2012 through 2016 does *not* include any carbon costs. Empire has not developed the environmental assumptions for the next triennial filing in 2013.

In addition to carbon, all of the alternate plans in the September 2010 IRP filing assumed costs for other emissions such as SO_2, NO_X and mercury. However, in the most recent five year business plan, which assumes a normalized operating scenario, Empire does not anticipate the need to purchase any allowances for these pollutants in the period 2012 through 2016.

A major environmental factor that was addressed in the September 2010 IRP was based on the Environmental Protection Agency's (EPA) regulation of mercury standards for electric generating units (EGU) requiring maximum achievable control technology (MACT). The last IRP referred to this as EGU MACT, which has also been referred to as Utility MACT or HAPS MACT within the industry. Most recently, it has become known and published as the Mercury and Air Toxics Standards (MATS) rule. The MATS rule was signed by the EPA Administrator on December 16, 2011 and later published in the Federal Register on February 16, 2012. MATS is set to become effective and require compliance within a three year timeframe (with flexibility for extensions for reliability reasons). With the official publication of the final rule, the compliance period will begin on April 16, 2012. Applicable to Empire's existing coal-fired electric generating units, the MATS rule establishes limitations based on maximum achievable control technology for mercury, non-mercury heavy metals, acid gas, and organic hazardous air pollutants. In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). This Compliance Plan largely follows the preferred plan presented in the most recent IRP. The Compliance Plan calls for the installation of a scrubber, fabric filter, and powder activated carbon injection system at the Asbury plant (collectively referred to as the Asbury air-quality control system or AQCS) by early 2015 at a cost ranging from $112 million to $130 million. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, an 18 megawatt (MW) steam turbine that is currently used for peaking purposes. The Compliance Plan also calls for the transition of the Riverton Units 7 and 8 from operation on coal to full operation on natural gas after the summer of 2013. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 for start-up, will be retired upon the conversion of Riverton Unit 12, a recently installed simple cycle combustion turbine, to a combined cycle unit. This conversion is currently scheduled for the 2016 timeframe.

An environmental regulation that has further developed since the last IRP filing in September 2010 is the Cross-State Air Pollution Rule (CSAPR)— formerly the Clean Air Transport Rule. On December 23, 2008 the Court remanded CAIR (Clean Air Interstate Rule) back to the EPA without vacating it until the EPA issued a new rule to replace CAIR. CSAPR is the EPA’s response to the court’s remand of CAIR. CSAPR is designed to reduce ozone and fine particulate emissions from power plants by setting standards for SO_2 and NO_X. CSAPR was finalized by the EPA in July 2011 requiring a reduction in NO_X and SO_2 levels starting in 2012 with further reductions starting in 2014. This rule was scheduled to take effect January 1, 2012; however, the District of Columbia Circuit Court of Appeals issued a last-minute stay in late December 2011 in response to legal challenges. Forty-five plaintiffs, including numerous “upwind” states and power companies brought litigation to challenge the rule. It is anticipated that the court will take up the substantive hearings in April 2012 with a ruling expected during the summer of 2012. As mentioned, this rule was designed to replace EPA's 2005 CAIR. With the stay of CSAPR, Empire is still subject to the requirements of CAIR. In addition, on January 26, 2012 the EPA signed a notice, which was published in the Federal Register, indicating that the Agency will not require compliance with the CSAPR supplemental rule while the stay is in effect. EPA finalized the supplemental rule on December 15, 2011 to include five additional states: Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, in the ozone season NO_X program in the CSAPR. In the meantime, Empire is moving forward with the aforementioned Compliance Plan to meet the Mercury and Air Toxics Standards (MATS) rule, which will assist in meeting final CSAPR requirements.

Another environmental factor that Empire is monitoring concerns cooling water intake structures. Riverton Units 7 and 8 (coal-fired units that can also operate on natural gas) and the coal-fired Iatan Unit 1 utilize once-through cooling water and are affected by EPA proposed regulations under the Clean Water Act (CWA) Section 316(b) Phase II, related to water intake structure adversity on aquatic life. The cost and specific requirements of the rule, scheduled to be finalized in July 2012, are not known at this time. Changes at each facility could range from flow velocity reductions to the installation of new pre-approved screening technology to minimize aquatic life impingement and entrainment. The coal-fired units Iatan Unit 2 and Plum Point Unit 1 are also included in the proposed regulation but were constructed with cooling towers, the proposed stated best technology available. Empire expects Iatan Unit 2 and Plum Point Unit 1 to be unaffected or minimally impacted by the final rule.

Empire will continue to monitor all of these environmental factors along with any other environmental factors or regulations that could impact the Company's operations.

2.2 Market and Fuel Prices Update

The most significant fuel price change since the September 2010 IRP filing is the recent drop in natural gas prices. Current market power prices are also lower than the IRP assumed due to its correlation with natural gas price. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce. The production of natural gas from shale formations has rejuvenated the natural gas industry in the United States. It is believed that the boom in production in shale formations has opened up natural gas reserves that are large enough to supply the U.S. for decades. The added production has boosted natural gas supplies in storage facilities underground to levels that are about 40 percent higher than the five-year average, according to the Energy Department. According to the U.S. Energy Information Administration (EIA) Short-Term Energy Outlook (February 7, 2012), natural gas spot prices averaged $2.67 per MMBtu at the Henry Hub in January 2012, down $0.50 per MMBtu from the December 2011 average and the lowest average monthly price since 2002. Abundant storage levels, as well as ample supply, have contributed to the recent low prices. EIA expects the Henry Hub spot price will begin to recover after this winter's inventory draw season ends and will average $3.35 per MMBtu in 2012 and $4.07 per MMBtu in 2013. One of the factors contributing to recent downward movements in natural gas prices has been unusually warm weather throughout much of the United States during the winter of 2011-2012, which has the effect of depressing natural gas demand for space heating. Natural gas working inventories continue to set new record seasonal highs and ended January 2012 at an estimated 2.86 trillion cubic feet (Tcf), about 24 percent above the same time last year. Additionally, the base natural gas prices in Empire's most recent IRP assumed that a carbon cap and trade system would be in place beginning in 2015, which was assumed to increase the use of natural gas as a fuel for the production of electricity, putting upward pressure on the natural gas price. As mentioned earlier, Empire's five year business plan for 2012 through 2016 does not contain any carbon costs.

The following table compares the base natural gas prices from the most recent IRP to the prices used in Empire's five year business plan (natural gas price estimates as of August 12, 2011) and to price estimates as of February 24, 2012. The spot market prices are based on NYMEX with a basis adjustment estimate for Southern Star Central Pipeline where Empire takes natural gas delivery. The weighted average values in the table represent the estimated total commodity cost of natural gas for Empire during the specified year, where the spot market gas prices are combined with Empire's natural gas hedging program in adherence with the Company's Risk Management Policy. At this time, Empire has not adopted a natural gas forecast for the 2013 IRP. The natural gas prices presented in the table below are subject to change. Empire is continually monitoring the natural gas market and reports natural gas prices on a weekly basis in the Company's Natural Gas Position Report. Other than the 2010 IRP columns, information from the Empire Natural Gas Position Report, at the date specified, was the basis for the data in the table.

Table 1. Natural Gas Price Comparison $/MMBtu

Year	2010 IRP Base CO_2 Case	2010 IRP No CO_2 Case		5-Year Plan Wtd. Average (8/12/2011)	5-Year Plan Spot Mkt Estimate (8/12/2011)		Wtd. Avg. Estimate (2/24/2012)	Spot Market Estimate (2/24/2012)
2012	6.12	6.13		5.74	4.39		5.00	2.76
2013	6.35	6.37		5.41	4.77		4.68	3.58
2014	7.07	7.11		5.15	5.00		4.24	3.92
2015	7.63	7.58		5.22	5.17		4.29	4.18
2016	8.03	7.95		5.35	5.35		4.65	4.65

As mentioned earlier, related to the recent decline in natural gas price estimates, the outlook for future wholesale market prices is lower today than they were when Empire prepared the September 2010 IRP. In the last IRP, market prices for the Southwest Power Pool (SPP) were projected by Ventyx, a consulting firm. These prices reflected conditions in the market expected to be experienced by Empire and utilized the most recent market information that was available at that time, which included the assumptions for natural gas prices that were discussed earlier. Market prices were derived for each of the carbon cost scenarios studied in the 2010 IRP. The base case market prices assumed that a carbon cap and trade system would be in place by 2015. As mentioned, this assumption was not carried forward into Empire's five year business plan.

The following table shows a comparison of estimated normal-weather market prices from the September 2010 IRP (with base carbon and no carbon costs); the Empire five year business plan (August 12, 2011); and with February 24, 2012 estimated natural gas prices. Market prices have not yet been developed for Empire's 2013 IRP, and the future prices depicted in the table below are subject to change.

Table 2. Market Price Comparison $/MWh

Year	2010 IRP Base CO_2 Case	2010 IRP No CO_2 Case		5-Year Plan (8/12/2011)		Estimate with updated natural gas prices (2/24/2012)
2012	40.44	40.44		37.90		~ 27.30
2013	40.66	40.66		41.04		~ 30.80
2014	44.24	44.24		42.79		~ 33.75
2015	54.41	44.17		44.19		~ 35.95
2016	56.28	44.76		44.55		~ 40.00

Overall, coal prices used in the September 2010 IRP compare closely to current coal price projections for Empire's coal units. This is especially true when considering the weighted average cost of coal for all of the Empire coal plants on a $/MMBtu basis. For the purposes of this update, a weighted average cost of coal has been developed to compare the 2010 IRP versus Empire's five year business plan. At this time, Empire has not developed coal costs for the 2013 IRP. As shown in the table below, the current projection for the weighted average cost of coal is slightly higher than the 2010 IRP for the period 2012 through 2016.

Table 3. Weighted Average Coal Price Comparison $/MMBtu

Year	2010 IRP Base Case	5-Year Plan
2012	2.02	2.08
2013	2.12	2.17
2014	2.14	2.15
2015	2.20	2.23
2016	2.22	2.27

2.3 Load Forecast Update

Empire has made updates to both the load forecasting methodology and the load forecast results since the last triennial compliance filing. In the September 2010 IRP filing, Empire utilized customer class forecasts using historical sales, weather, customer counts, and, at times, trend binaries and input from the Commercial Services Department. System energy and peak demands were forecast with linear regression analysis employing the "least squares" method to determine a best fit line through a set of historical observations. All of these methods fall into the category of statistical modeling, not end-use modeling. In the last IRP filing, Empire was granted variances from the IRP Rule's requirements for end-use modeling. Since the load forecast is one of the first steps in developing an IRP, the load forecast for the September 2010 IRP filing was developed around mid-2009.

Following the last IRP filing and the subsequent IRP Rule revision, Empire presented a proposal for a new load forecasting methodology to its IRP Stakeholder Advisory Group. With the help of Itron consulting, Empire has already created a preliminary demand and energy forecast utilizing the new method. This new method can be described as a Statistically Adjusted End-Use (SAE) model for the Residential and Commercial classes. The other classes rely on econometric models that use elements of the SAE data as drivers into the model. The SAE models rely upon technology saturations and efficiencies developed by the EIA/DOE. The models also utilize weather, the price of electricity and economic drivers.

The following tables show the update to the load forecast. It compares the September 2010 IRP base load forecast versus the preliminary base load forecast utilizing the updated SAE methodology. The updated load forecast depicts a slower anticipated rate of load growth as a result of the more recent assumptions which includes a prolonged economic downturn. Both forecasts contain the impacts of existing DSM, increased efficiency standards as well as conservation trends, but no impacts of future DSM. As a result, the more recent forecast contains recent energy efficiency and conservation trends that were not present in the 2010 IRP forecast. The more recent forecast presented in this update also contains a slightly lower anticipated customer count in the early years of the forecast due to the 2011 Joplin tornado. The base load forecast from the September 2010 IRP filing had a compound demand growth rate (net peak demand) of about 2.0% and a compound energy growth rate (net system input or NSI) of about 2.4%. The low-growth case from the September 2010 IRP filing had a compound demand growth rate of about 1.60% and a compound energy growth rate of about 1.91%. For comparison, the corresponding compound growth rates for this 2012 IRP update is about 0.77% for demand and about 0.81% for energy.

Table 4. Net Peak Demand Forecast Comparison

Year	Net Peak Demand (MW) 2010 IRP	2010 IRP Assumed Peak Growth		Net Peak Demand (MW) 2012 IRP Update	2012 IRP Update Assumed Peak Growth		Forecast Difference (MW)
2012	1,216	-		1,186	-		-30
2013	1,240	2.0%		1,190	0.3%		-50
2014	1,265	2.0%		1,197	0.6%		-68
2015	1,290	2.0%		1,205	0.6%		-85
2016	1,316	2.0%		1,214	0.7%		-102
2017	** **	** **		** **	** **		** **
2018	** **	** **		** **	** **		** **
2019	** **	** **		** **	** **		** **
2020	** **	** **		** **	** **		** **
2021	** **	** **		** **	** **		** **
2022	** **	** **		** **	** **		** **
2023	** **	** **		** **	** **		** **
2024	** **	** **		** **	** **		** **
2025	** **	** **		** **	** **		** **
2026	** **	** **		** **	** **		** **
2027	** **	** **		** **	** **		** **
2028	** **	** **		** **	** **		** **
2029	** **	** **		** **	** **		** **

Table 5. Annual Energy Forecast Comparison
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Year	Annual Energy NSI (MWh) 2010 IRP	2010 IRP Assumed NSI Growth		Annual Energy NSI (MWh) 2012 IRP Update	2012 IRP Update Assumed NSI Growth		Forecast Difference (MWh)

2.4 Capital Costs and Interest Rates Update

After reviewing the interest rates and capital costs for generic resources in the September 2010 IRP, it has been determined that there are no updates to report at this time. Empire will reevaluate the capital costs and all other assumptions during the development of the 2013 IRP. Additionally, there have been no significant changes to the cost information used for the proposed conversion of Riverton Unit 12 to a combined cycle. Empire does have updated cost information for the Asbury AQCS project. This project, which consists of the installation of a circulating dry scrubber, fabric filter and powder activated carbon injection system, was studied in the last IRP. At that time, the project cost estimates were based on a preliminary engineering study. The last IRP assumed a cost of roughly $158 million. After completing the request for proposal (RFP) process and signing a contract, Empire now expects the cost for the Asbury AQCS to range from

$112 million to $130 million. The expected cost of the landfill and bottom ash conveyance system at Asbury has not changed.

3.0 Resource Acquisition Strategy Update

Empire has made progress in implementing the resource acquisition strategy that was outlined in the September 2010 IRP. Specifically this report will provide an update on the following items:

1) Demand-side management (DSM)
2) Asbury air-quality control system (AQCS) project
3) Riverton coal units
4) Riverton 12 combustion turbine (CT) conversion to combined cycle (CC)

3.1 Demand-Side Management (DSM)

On February 28, 2012 Empire made a filing with the Missouri Public Service Commission (Commission) seeking Commission approval of a new Missouri demand-side management portfolio, which includes the existing DSM programs (some with modifications) and four new DSM programs, and the implementation of a new Demand Side Investment Mechanism (DSIM) to recover the revenue requirement associated with Empire's proposed DSM portfolio. The filing was made under the rules of the Missouri Energy Efficiency Investment Act (MEEIA filing) and has been assigned File No. EO-2012-0206. Empire made this MEEIA filing to comply with the previously mentioned agreement reached in Empire's most recent September 2010 IRP. Empire retained the consultant Applied Energy Group (AEG) to re-examine its existing DSM portfolio and analyze the four new DSM programs Empire agreed to screen as part of the agreement reached in the latest IRP to determine if the new DSM programs and existing DSM programs were cost effective. AEG determined that all of the new DSM programs Empire agreed to examine in the IRP agreement are cost effective, and all of Empire's existing DSM programs, with the exception of the low-income new homes program, continue to be cost effective using the Total Resource Cost (TRC) test. The four additional DSM programs are:

- residential high efficiency lighting program
- residential home energy comparison program
- Energy Star appliance rebate program
- refrigerator recycling program

The Energy Star appliance rebate program encompasses a range of appliances including refrigerators, dehumidifiers, washing machines, and room air conditioners. These new programs or variations of these programs were evaluated in the September 2010 IRP, but at that time, the analysis determined their inclusion as selected resources should occur at a later time in the planning horizon. However, in the September 2010 IRP agreement Empire agreed to augment the demand-side resource portfolio contained in the resource acquisition strategy of the September 2010 IRP filing by including these programs along with the existing DSM portfolio in a MEEIA filing. Empire along with AEG also reviewed the participation levels, design and implementation of the existing programs for the MEEIA filing.

On December 30, 2011 the Arkansas Public Service Commission issued Order No. 34 in Docket No. 07-076-TF, approving Empire's Energy Efficiency (EE) Plan for program years 2012 and 2013 in Arkansas. The programs are designed to meet the Arkansas energy-savings targets. Empire plans to continue the recovery of its EE program costs through the Energy Efficiency Cost Recovery (EECR) Rider for its Arkansas customers. Empire serves approximately 4,300 electric customers in northwest Arkansas.

The Oklahoma Corporation Commission approved an Empire updated DSM Rider on December 16, 2011 to be charged to Oklahoma customers for recovery of EE program costs beginning January 1, 2012. Empire has a pilot DSM program in Kansas. The Kansas Corporation Commission approved an EE Rider on December 21, 2011 in Docket No. 12-EPDE-497-TAR to recover EE program costs. This EE Rider went into effect for Kansas customers on January 1, 2012. Empire serves approximately 4,700 electric customers in northeast Oklahoma and approximately 9,900 electric customers in southeast Kansas.

3.2 Asbury Air-Quality Control System (AQCS) Project

The Asbury plant, located near Asbury, Missouri consists of two coal-fired units totaling 207 MW. Unit 1 (189 MW) was installed in 1970 and Unit 2 (18 MW) was installed in 1986. In the September 2010 IRP Empire studied various scenarios related to the Asbury coal-fired plant. This included the potential retrofitting of the plant to include installation of additional environmental equipment so the plant would be in compliance with prospective environmental regulations that could require maximum achievable control technologies in the 2015 timeframe as was discussed in Section 2.1. Asbury has already installed selective catalytic reduction equipment (SCR) in 2008. Several IRP plans, including the preferred plan, proposed the installation of a scrubber to reduce SO_2, a fabric filter to reduce particulate matter, and a powder activated carbon injection system to reduce mercury at the Asbury plant (collectively referred to as the Asbury air-quality control system or AQCS). As previously presented in Section 2.1, Empire's Compliance Plan does include the Asbury AQCS project and the retirement of Unit 2 in the 2015 timeframe as the preferred plan had proposed. In Empire's last IRP a commitment was made to investigate permitting requirements, issue a request for proposal (RFP) for the project and evaluate the RFP bids.

In October 2010, Black & Veatch (B&V) completed the Asbury AQCS study that was under way at the time that Empire filed its September 2010 IRP. In January 2011, Empire's Asbury AQCS team began working with B&V to develop technical specifications based on the recommendations of the Asbury AQCS study. These technical specifications were delivered to Empire in May 2011, at which time Empire began working with Sega, Inc. to issue an RFP and to evaluate the resulting proposals. The RFP was issued on June 17, 2011 with bids due to Empire by September 15, 2011.

Empire spent approximately two months evaluating the five proposals before selecting the proposal submitted by a joint venture of Alberici Constructors (St. Louis, MO) and Stanley Consultants (Muscatine, IA). Empire executed a contract with the joint venture on January 16, 2012, requiring completion of the project by February 1, 2015 which will allow the Asbury Plant to comply with the MATS rule. The AQCS will also enable Empire to comply with the CAIR and/or the CSAPR as was described in Section 2.1. The environmental compliance derived from this project will allow Empire to continue to meet customer's future demand for electricity with a diversified mix of resources. As reported in Section 2.4, Empire now expects the cost for the Asbury AQCS to range from \$112 million to \$130 million as compared to the \$158 million estimate in the last IRP.

Associated with the Asbury AQCS project and other pending environmental regulations is the potential need for an ash landfill and bottom ash conveyance equipment at the Asbury plant. In mid to late 2012 the EPA is expected to finalize new regulations pursuant to its authority under the Federal Resource Conservation and Recovery Act (RCRA) governing the management and storage of Coal Combustion Residuals (CCR), often referred to as coal ash. Empire anticipates the new rule will require the permitting of a new ash landfill along with the conversion of the existing wet ash handling to a dry system for the Asbury AQCS project. The permit application and approval process for the landfill construction permit is estimated to be 60 months. It is anticipated that Empire's existing ash impoundments will be allowed to close in place in accordance with applicable state requirements. The specific start time for implementing closure and post closure construction and site management projects for the older ash ponds is not known at this time.

3.3 Riverton Coal Units

The Riverton coal units are two small coal-fired units known as Riverton Units 7 and 8. Unit 7 is rated at 38 MW but operates at roughly 24 to 27 MW on coal; it was installed in 1950. Unit 8 is rated at 54 MW and operates at about 45 MW on coal; it was installed in 1954. Both units can also operate solely on natural gas or over-fire with natural gas while burning coal to reach the rated capacity levels. In the September 2010 IRP, Empire affirmed that it would monitor the Riverton Unit 7 and 8 coal-fired units for environmental compliance to determine at what point the units should be retired or transitioned to natural gas operation, if needed, prior to their retirement. The environmental Compliance Plan that was introduced in Section 2.1 calls for the transition of the Riverton Units 7 and 8 from operation on coal to full operation on natural gas after the summer of 2013. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 for start-up, will be retired upon the conversion of Riverton Unit 12, a simple cycle combustion turbine installed in 2007, to a combined cycle unit. This conversion is currently scheduled for the 2016 timeframe. The timing of both the Riverton coal units' proposed transition to natural gas and their proposed retirement have been changed since the preferred plan was selected in the 2010 IRP. This is further discussed in Section 4.2 Riverton Coal Units Preferred Plan Update.

3.4 Riverton 12 Combustion Turbine (CT) Conversion to Combined Cycle (CC)

Riverton Unit 12 is a natural gas-fired Siemens V84.3A2 combustion turbine that was installed at the Riverton power plant in Riverton, Kansas in 2007. It is currently rated at 142 MW for the summer peak season and it is primarily used as a peaking unit. When this unit was originally constructed 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 (Riverton combined cycle project) was considered as a candidate resource in the most recent IRP (September 2010 IRP). In all 17 plans that were studied, including the preferred plan, the Riverton combined cycle project was selected as the first supply-side resource addition for the 2015 timeframe. This project is assumed to add about 100 additional MW to the system, making the Riverton combined cycle a roughly 250 MW unit upon completion. The Riverton combined cycle project will utilize existing site infrastructure and will incorporate the existing Riverton Unit 12 combustion turbine into a combined cycle unit. A heat recovery steam generator (HRSG) will be installed along with a new steam turbine and a cooling tower to provide cooling water for the condenser. A new control room and control system will also be installed to operate the unit. Upon completion of the project, Riverton Units 7, 8 and 9 will retire.

As will be discussed in Section 4.1, Riverton Combined Cycle Project Preferred Plan Update, this project has shifted about one year making it a 2016 timeframe project. Thus, all of the implementation plan schedules for this project from the last IRP have shifted accordingly. As a result, there are not any updates to report at this time. Shortly, an internal team will assemble and begin working on operating and construction permitting; water rights issues; RFP development; RFP evaluation and equipment procurement; and construction oversight.

4.0 Preferred Plan Update

This preferred plan update will focus on the early years of the IRP preferred plan (2012 through 2016) to coincide with the most recently approved five year business plan. Obviously, the major factors that *could* influence the preferred plan are the identified critical uncertain factors that were updated in Section 2 of this report. Namely the factors are: (1) environmental factors, (2) market and fuel prices, (3) future load growth predictions, and (4) capital costs. With all of these factors considered, the near term resource plan in the current five year business plan largely follows the preferred plan in the September 2010 IRP with some modifications. The following table compares the major projects from the preferred plan as outlined in the September 2010 IRP and the current plan from the five year business plan as of March 2012.

Table 6. Preferred Plan Project Comparison

Project	Most Recent IRP (September 2010)	Most Recent 5-Year Business Plan (March 2012)	Change
Asbury AQCS project	AQCS project completed in the 2015 timeframe	AQCS project completed in the 2015 timeframe	No significant timing change; lower project cost estimate
Asbury Unit 2 retirement	Retires in 2015 with the completion of the AQCS project	Retires in 2015 with the completion of the AQCS project	No change
Riverton coal (Units 7, 8) transition to natural gas	Transition from coal to natural gas in the 2015 timeframe	Transition from coal to natural gas following the summer of 2013	Transition from coal to natural gas about 15 to 16 months earlier
Riverton retirements (Units 7, 8 & 9)	Retire at the end of 2018	Retire in 2016 with the conversion of Riverton 12 to combined cycle	Retire about 2 to 2.5 years earlier
Riverton Unit 12 CT conversion to combined cycle (CC)	Convert Riverton 12 to CC in the 2015 timeframe	Convert Riverton 12 to CC in the 2016 timeframe	Convert to CC about one year later; no significant change to cost estimate
DSM projects	Proposed a DSM portfolio of about seven programs in the 2012-2016 timeframe	Make a MEEIA filing with four additional programs; reevaluate existing programs; and request a DSIM	Propose four new programs and higher participation levels for some of the existing programs

4.1 Riverton Combined Cycle Project Preferred Plan Update

Riverton Unit 12 and the Riverton combined cycle project were described in Section 3.4. As previously mentioned, the potential conversion of the 142 MW Riverton Unit 12 combustion turbine to a 250 MW combined cycle unit by adding a heat recovery steam generator, a steam turbine, a cooling tower and a control system, was a candidate resource in the most recent IRP. It was selected as a viable first supply-side addition in all plans that were studied, and was included in the preferred plan for the 2015 timeframe.

As set forth in the Compliance Plan that has been described in this report, the Riverton combined cycle project is now scheduled to be completed in the 2016 timeframe. In the Executive Summary of the September 2010 IRP Report on page ES-4, the following statement was made about the timing of this resource:

As of the date of this IRP filing (September 2010), Empire has selected a Preferred Plan that represents the actions that it would take if the conditions that existed at the time of the analysis still existed at the time of the filing. 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 2015 timeframe resource may be delayed until 2016 or beyond. However, for purposes of this IRP, it will be referred to as the "2015 timeframe resource".

Since the 2010 IRP report was filed, Empire has developed other load forecasts including the preliminary SAE load forecast that was presented in Section 2.3 of this report. The lower anticipated load growth that has been described, along with the development of the environmental compliance plan, has indeed shifted the Riverton combined cycle project from the 2015 timeframe to the 2016 timeframe.

4.2 Riverton Coal Units Preferred Plan Update

As mentioned earlier in Section 2.1, Empire's Compliance Plan calls for the transition of Riverton Units 7 and 8 (Riverton coal units) from operation on coal to full operation on natural gas after the summer of 2013, and for their retirement upon the completion of the Riverton combined cycle project in 2016. These units were designed to operate on coal and/or natural gas and for many years they have operated primarily on coal with the ability to over-fire with natural gas in order to reach their rated capacity. As a result there will be no additional costs to transition Riverton Units 7 and 8 to full operation on natural gas. This is a slightly different plan for these units than what was proposed in the preferred plan from the September 2010 IRP. In the last IRP, Riverton Units 7 and 8 were assumed to transition from coal to natural gas in the 2015 timeframe. By making the transition from coal to natural gas about 15 to 16 months earlier, Empire may gain additional flexibility with regards to upcoming environmental regulations. For example, if the District of Columbia Circuit Court of Appeals were to lift the current stay on the CSAPR, the rule could go into effect as soon as 2013. In addition, one of the changes from the CAIR to the final CSAPR was the creation of two trading groups for SO_2. Empire's Missouri coal-fired units (Asbury, Iatan 1 and Iatan 2) are in Group 1 while Riverton Units 7 and 8, which are located in Kansas, are in Group 2. Based on the CSAPR, Empire cannot trade allowances between the two Groups. As such, Empire could lose some flexibility under this scenario related to how it could trade its allowances on an intra-company basis. As a result, Empire is preparing to transition Riverton Units 7 and 8 to natural gas sometime after the summer of 2013. By transitioning to natural gas in this timeframe Empire will still be able to reliably and economically meet its customers' demands for electricity—especially with the aforementioned decline in load growth, natural gas prices and market prices since the last IRP—and continue to transition these units toward their eventual retirement. In this timeframe, Riverton Units 7 and 8 will be approximately 64 and 60 years old respectively.

The Compliance Plan also calls for Riverton Units 7 and 8, along with Riverton Unit 9 (12 MW), a small combustion turbine that requires steam from Unit 7 for start-up, to be retired upon the conversion of Riverton Unit 12, a recently installed simple cycle combustion turbine, to a combined cycle unit. The Riverton Unit 12 conversion and the retirements of Riverton Units 7, 8 and 9 are currently scheduled for the 2016 timeframe. The impending MATS rule, which was discussed in Section 2.1, would prohibit the continued operation of Riverton Units 7 and 8 on coal. The MATS rule would require maximum achievable control technology for mercury, non-mercury heavy metals, acid gas, and organic hazardous air pollutants. It would be cost prohibitive to retrofit these small sixty-plus year old units that are near the end of their useful life, with the new environmental equipment that the rules would require. This is a slightly different retirement date than was proposed in the September 2010 IRP preferred plan. While the 2010 IRP did examine multiple alternate plans that did assume the retirement of the Riverton coal units in the 2015 timeframe, the preferred plan assumed a transition to natural gas in the 2015 timeframe and a retirement at the end of year 2018. Thus, the current Compliance Plan assumes a retirement date approximately 2 to 2.5 years earlier than the 2010 IRP. There are several factors that have led to modifying the retirement date. The ages of the units are a primary consideration for their retirement and now, with the lower expected load growth, Empire does not anticipate the need to retain these units through 2018 for capacity purposes. After their transition to natural gas operation to meet the impending environmental regulations, the units' operating hours are expected to be minimal. Additionally, the proposed cooling water intake structure rule (Section 316(b) of the Clean Water Act which requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available) in conjunction with lower anticipated natural gas and market prices also hasten an earlier retirement date than the 2010 IRP preferred plan had assumed. Finally, employee logistics would make it difficult and cost prohibitive to operate Units 7 and 8 once Riverton Unit 12 is converted to a combined cycle since the combined cycle will require a new control room that would not be common with Units 7 and 8.

4.3 Load and Capability Balance Report Update

The Load and Capability Balance Reports for both the most recent IRP (September 2010) and the most recent five year business plan (March 2012) are presented on the following pages for comparison. The updated capacity balance report contains current unit ratings from the most recent capacity tests; the updated preliminary load forecast utilizing the SAE forecasting methodology; the timing change for the Riverton combined cycle project; and the retirement timing changes for Riverton Units 7, 8, and 9.

Table 7. Load and Capability Balance Report – Most Recent IRP (September 2010)

Rated Capacity (MW)	Primary Fuel	*2012*	*2013*	*2014*	*2015*	*2016*
Riverton 7	Coal/Nat Gas	38	38	38	38	38
Riverton 8	Coal/Nat Gas	54	54	54	54	54
Asbury	Coal	207	207	207	182	182
Iatan	Coal	85	85	85	85	85
Iatan 2	Coal	102	102	102	102	102
Plum Point (Total)	Coal	100	100	100	100	100
Ozark Beach	Hydro	16	16	16	16	16
Riverton 9	Natural Gas	12	12	12	12	12
Riverton 10	Natural Gas	16	16	16	16	16
Riverton 11	Natural Gas	16	16	16	16	16
Riverton 12	Natural Gas	150	150	150	-	-
State Line 1	Natural Gas	96	96	96	96	96
State Line CC	Natural Gas	300	300	300	300	300
Energy Center 1	Natural Gas	85	85	85	85	85
Energy Center 2	Natural Gas	84	84	84	84	84
Energy Center 3	Natural Gas	49	49	49	49	49
Energy Center 4	Natural Gas	49	49	49	49	49
Elk River 150 MW Windfarm	Wind PPA	7	7	7	7	7
Meridian Way 105 MW Windfarm	Wind PPA	8	8	8	8	8
Total Existing		1,474	1,474	1,474	1,299	1,299
Riverton CC conversion	Natural Gas				250	250
New DSM Estimate		0.70	0.97	1.21	9.94	13.31
Total Proposed		0.70	0.97	1.21	259.94	263.31
Total Resource for Plan		1,475	1,475	1,475	1,559	1,562
System Peak (with existing DSM)		1,216	1,240	1,265	1,290	1,316
Capacity Reserves		259	235	210	269	246
Reserve Margin Required		13.7%	13.7%	13.7%	13.7%	13.7%
Capacity Margin Required		12%	12%	12%	12%	12%
Required Capacity		1,382	1,409	1,437	1,466	1,496
Capacity Margin		17.5%	15.9%	14.3%	17.2%	15.7%
Capacity Balance		93	66	38	93	66

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Table 8. Load and Capability Balance Report – 5-Year Plan (March 2012)

Rated Capacity (MW)	Primary Fuel	*2012*	*2013*	*2014*	*2015*	*2016*
Riverton 7	Coal/Nat Gas	38	38	38	38	-
Riverton 8	Coal/Nat Gas	54	54	54	54	-
Asbury	Coal	207	207	207	183	183
Iatan	Coal	85	85	85	85	85
Iatan 2	Coal	102	102	102	102	102
Plum Point (Total)	Coal	100	100	100	100	100
Ozark Beach	Hydro	16	16	16	16	16
Riverton 9	Natural Gas	12	12	12	12	-
Riverton 10	Natural Gas	16	16	16	16	16
Riverton 11	Natural Gas	17	17	17	17	17
Riverton 12	Natural Gas	142	142	142	142	-
State Line 1	Natural Gas	94	94	94	94	94
State Line CC	Natural Gas	297	297	297	297	297
Energy Center 1	Natural Gas	82	82	82	82	82
Energy Center 2	Natural Gas	82	82	82	82	82
Energy Center 3	Natural Gas	49	49	49	49	49
Energy Center 4	Natural Gas	49	49	49	49	49
Elk River 150 MW Windfarm	Wind PPA	7	7	7	7	7
Meridian Way 105 MW Windfarm	Wind PPA	8	8	8	8	8
Total Existing		1,457	1,457	1,457	1,433	1,187
Riverton CC conversion	Natural Gas					250
New DSM Estimate		1.06	1.82	2.55	11.42	14.93
Total Proposed		1.06	1.82	2.55	11.42	264.93
Total Resource for Plan		1,458	1,459	1,460	1,444	1,452
System Peak (with existing DSM)		1,186	1,190	1,197	1,205	1,214
Capacity Reserves		272	269	263	239	238
Reserve Margin Required		13.7%	13.7%	13.7%	13.7%	13.7%
Capacity Margin Required		12%	12%	12%	12%	12%
Required Capacity		1,348	1,352	1,360	1,369	1,380
Capacity Margin		18.7%	18.4%	18.0%	16.6%	16.4%
Capacity Balance		110	107	99	75	72

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5.0 Empire Special Contemporary Issues

According to the Chapter 22—Electric Utility Resource Planning Rules, special contemporary issues means a written list of issues contained in a Commission order with input from Staff, Public Counsel, and interveners that are evolving new issues, which may not otherwise have been addressed by the utility or are continuations of unresolved issues from the preceding triennial compliance filing or annual update filing. In this section of the report, Empire will address the special contemporary issues that were established by Commission Order in File No. EO-2012-0040.

5.1 Impacts of the May 22, 2011 Joplin Tornado

Analyze and document how Empire's load-forecast will account for the impact of tornado damage in its service territory. Analyze and document how on-going recovery efforts impact Empire's capacity balance and participation in DSM programs. Analyze and document how these changes impact the preferred resource plan or contingency plans.

In Section 2.3, an updated Empire load forecast was presented. This forecast was recently prepared and incorporates the impact of the Joplin tornado. The Joplin tornado recovery assumptions impact the near-term customer count, which is an assumption in the load forecast. However, the lower growth in peak demand and lower energy growth displayed in Empire's updated load forecast in Section 2.3 has more to do with the projected economic and conservation and efficiency trend assumptions than the impact of the Joplin tornado.

Empire has continuously monitored recovery efforts since the EF-5 tornado (the highest rating on the Enhanced Fujita Scale of tornado strength) devastated south central Joplin, the village of Duquesne, and portions of rural Jasper and Newton counties on May 22, 2011. The storm damaged or destroyed homes, churches, schools, medical facilities and businesses. Immediately following the storm nearly 20,000 customers were left without power. The storm restoration efforts that began just after the storm restored power to nearly all who could potentially receive it by May 31, 2011. At that time, the estimated number of customers not ready to accept electric service was in the range of 5,000 to 6,000 based on a damage boundary area outlined by the Federal Emergency Management Agency (FEMA) and refined by Empire field work. This represented an immediate customer loss of about 3.2%, but many customers that were displaced steadily relocated within the service territory. By the end of June 2011, about one month following the storm, the number of lost customers had dropped to about 4,000. Throughout the summer, autumn and winter of 2011 and into early 2012, the electric customer count in the Joplin and Webb City area has continued to show a post-tornado recovery. Joplin schools, whose facilities were extremely hard hit by the tornado, actually began the 2011-2012 school year on time—albeit in several temporary locations—less than three months after the storm. As of January 2012, post-tornado customer count in Empire's Joplin/Webb City district has increased by just over 2,000 customers since June 2011, representing a recovery of just over 50% of the estimated 4,000 customers that were lost due to the tornado. Several of the larger customers in the Rangeline Road commercial district have already rebuilt. St. John's Medical Center, a large user of electricity, has set up temporary facilities, and has begun construction on a new state-of-the-art hospital that is planned to be open in the early 2015 timeframe. These are examples of the tornado recovery efforts that Empire continues to monitor. The impact of the ongoing recovery efforts were incorporated into the most recent load forecast assumptions.

The capacity balance report presented in Table 8 of Section 4.3 includes the most recent load forecast, which includes the impact of the Joplin tornado. The loss of load associated with the Joplin tornado affects the early years of the load forecast, but lost load does not impact Empire's preferred plan or contingency plans.

The tornado recovery efforts may create some additional opportunities for energy efficiency as the rebuilding occurs. Several of the high-efficiency air conditioning (AC) rebates that Empire has processed during the past few months have been for homes in or near the tornado damage area, and several of the commercial rebuilds have utilized Empire's Commercial & Industrial rebate program. Rebuilding within the tornado damage area has been slow, as many residents and businesses have moved to existing locations outside the damage area, but as new homes and businesses are built in and around this area at some point in the future, customers may elect to participate in Empire's energy efficiency programs.

5.2 Loss of Significant Load

Investigate and document the impacts on Empire's preferred resource plan and contingency plans of a loss of significant load for the short term and potentially for the long term that may be the result of a prolonged double dip recession or a large customer or group of customers no longer taking service from Empire.

As discussed in Section 5.1, Empire recently experienced a significant loss of customers due to the May 22, 2011 Joplin tornado. As explained in that section, the bulk of that loss is considered relatively short-term in nature as Empire's customer count has recovered with the ongoing recovery efforts. The Joplin tornado does have an impact on the load forecast—as recovery does take time and perhaps not all customers will return—but it tends to be less significant in the long-term from a resource planning perspective. As a result, this event is not expected to have a significant impact on the preferred plan.

Although Empire does not expect a long-term loss of significant load from the loss of a major customer or a group of larger customers in the foreseeable future, in the most recent IRP (September 2010), Empire investigated this type of significant long-term loss of load in a couple alternative plans. Those alternate plans were labeled Plans 7 and 8 and examined the potential loss of a large on-system wholesale customer (since the last IRP was filed, however, new ten year unbundled full-requirement contracts have been signed with each of the on-system wholesale customers, where the generation component utilizes a generation formula rate that is updated annually). A description of those plans and the performance measures for those plans can be found in Volume 5 Integrated Resource Analysis, Risk Analysis and Strategy Selection from File No. EO-2011-0066.

In the last IRP, the resource selections and capacity balance reports for Plans 7 and 8 can also be compared to Plan 4 which was selected as the preferred plan to see the loss of load impact on the preferred plan.

To address this contemporary issue, Empire has investigated the potential impact on load of a double-dip recession utilizing the updated SAE load forecasting methodology described in Section 2.3. Economy.com, a provider of economic and demographic projections, was the source of the economic data used in Empire's forecast presented in Section 2.3. Among the several potential scenarios developed by this service is an economic forecast scenario that Economy.com calls the "Double-Dip Recession." This scenario is described by Economy.com as follows:

In this recession scenario, in which a second downturn develops, there is a 90% probability that the economy will perform better, broadly speaking, and a 10% probability that it will perform worse. The downside 10% "Double-Dip Recession" scenario develops as Middle East tension increases to the point that the perceived risk of reduced oil supplies causes the price of oil to rise to a peak of $126 per barrel in early 2012 for West Texas Intermediate. Consumer spending declines as higher gasoline prices cut into discretionary income, and consumer confidence falls significantly. Further, expectations of higher inflation and gridlock caused by disagreement over the federal debt crisis cause Treasury and corporate bond yields to rise more than a percentage point above the baseline level, causing business investment to decline. Additionally, European debt problems magnify to the extent that a significant second European recession develops, and earthquake-related destruction in Japan slows overall Asian growth, causing U.S. exports to decline. Additionally, U.S. state and local government budget problems require greater than expected layoffs and declines in spending.

Tables 9 and 10, presented below, show the difference in the updated preliminary base load forecast (demand and energy) that was presented in Section 2.3 and the same basic forecast approach which utilizes the "Double-Dip Recession" economic projection from Economy.com. Since the MW impacts in the two forecasts are minimal (a recession scenario compared to a double-dip recession scenario), this "Double-Dip Recession" scenario is not expected to change the *updated* preferred plan for the period 2012-2016 that has been described in this report and whose load and capacity balance report was shown in Table 8.

Table 9. Net Peak Demand Forecast Comparison – Double-Dip Recession

Year	Net Peak Demand (MW) 2012 IRP Update	2012 IRP Update Assumed Peak Growth		Net Peak Demand (MW) Double-Dip Recession Scenario	Double-Dip Recession Assumed Peak Growth		Forecast Difference (MW)
2012	1,186	-		1,177	-		-9
2013	1,190	0.3%		1,177	0.0%		-13
2014	1,197	0.6%		1,183	0.6%		-14
2015	1,205	0.6%		1,194	0.9%		-12
2016	1,214	0.7%		1,207	1.1%		-7
2017	** **	** **		** **	** **		** **
2018	** **	** **		** **	** **		** **
2019	** **	** **		** **	** **		** **
2020	** **	** **		** **	** **		** **
2021	** **	** **		** **	** **		** **
2022	** **	** **		** **	** **		** **
2023	** **	** **		** **	** **		** **
2024	** **	** **		** **	** **		** **
2025	** **	** **		** **	** **		** **
2026	** **	** **		** **	** **		** **
2027	** **	** **		** **	** **		** **
2028	** **	** **		** **	** **		** **
2029	** **	** **		** **	** **		** **

Table 10. Annual Energy Forecast Comparison – Double-Dip Recession
****HIGHLY CONFIDENTIAL IN ITS ENTIRETY****

Year	Annual Energy NSI (MWh) 2012 IRP Update	2012 IRP Update Assumed NSI Growth		Annual Energy NSI (MWh) Double-Dip Recession Scenario	Double-Dip Recession Assumed NSI Growth		Forecast Difference (MWh)

5.3 Impacts of Newly Proposed Aggressive Environmental Regulations

Investigate and document the updated impacts of newly proposed aggressive environmental regulations on Empire's preferred resource plan and contingency plans.

Since environmental costs were identified as an IRP critical uncertain factor, the newly proposed aggressive environmental regulations have been described in Section 2.1 of this report. The changes to the preferred plan, while nominal, were discussed in Section 4. Please refer to those sections for more information.

In summary, some of the newly proposed and developing environmental regulations that could impact resource planning include the following:

- Mercury and Air Toxics Standards (MATS) rule
- Cross-State Air Pollution Rule (CSAPR)
- Cooling water intake structure issues
- Federal Resource Conservation and Recovery Act (RCRA) governing the management and storage of Coal Combustion Residuals (CCR), often referred to as coal ash

Empire continues to monitor these and other potential environmental issues that could impact the Company's operations. In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). This Compliance Plan largely follows the preferred plan presented in the most recent IRP. The Compliance Plan calls for the installation of a scrubber, fabric filter, and powder activated carbon injection system at the Asbury plant (collectively referred to as the Asbury air-quality control system or AQCS) by early 2015 at a cost ranging from $112 million to $130 million. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, an 18 megawatt (MW) steam turbine that is currently used for peaking purposes. The Compliance Plan also calls for the transition of the Riverton Units 7 and 8 from operation on coal to full operation on natural gas after the summer of 2013. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 for start-up, will be retired upon the conversion of Riverton Unit 12, a recently installed simple cycle combustion turbine, to a combined cycle unit. This conversion is currently scheduled for the 2016 timeframe.

5.4 Potential or Proposed Changes in State or Federal Environmental or Renewable Energy Standards

Analyze potential or proposed changes in state or federal environmental or renewable energy standards and report how those changes would affect Empire's plans for compliance with those standards.

On November 4, 2008, Missouri voters approved the Clean Energy Initiative (Proposition C). This initiative requires Empire and other investor-owned utilities (IOUs) in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase renewable energy credits (RECs), at the rate of at least 2% of retail sales by 2011, and increasing to at least 15% by 2021. Two percent of this amount must be solar. However, Empire believes it has an exemption from the solar requirement. A challenge to this exemption, brought by two customers and Power Source Solar, Inc., was dismissed on May 31, 2011 by the Missouri Western District Court of Appeals. The plaintiffs filed in the Missouri Supreme Court for transfer of the case from the Missouri Western District to the Missouri Supreme Court, but the transfer was denied.

The Missouri Renewable Energy Standard (MORES) compliance rules were published by the Commission on July 7, 2010. Missouri IOUs and others initiated litigation to challenge these rules. On June 30, 2011, a Cole County Circuit Court judge ruled that portions of the rules were unlawful and unreasonable, in conflict with Missouri statute and in violation of the Missouri Constitution. Subsequent to that decision, a portion of the appeal was dropped and the entire order was stayed. On December 27, 2011 the judge issued another order that was identical to the stayed order with the constitutionality issue omitted. The Commission has appealed this ruling.

Empire has satisfied the current compliance requirements of the rule which requires the generation or purchase of electricity from renewable energy sources of at least 2% of retail sales by 2011, increasing to at least 15% by 2021.

However, there have been proposed changes to the MORES. Currently there is an initiative petition approved for circulation in Missouri which proposes a statutory amendment to RSMo Chapter 393, relating to renewable energy. The proposed changes would prescribe by rule a portfolio requirement far exceeding the current requirements. The table below shows the timing and energy requirements for both the existing MORES and the proposed initiative petition:

Table 11. Renewable Energy Standard Comparison

Current Dates	Current RES Percentage (no less than)	Proposed Dates	Proposed Percentage (no less than)
2011-2013	2	2014-2016	5
2014-2017	5	2017-2019	10
2018-2020	10	2020-2022	15
Beginning 2021	15	2023-2025	20
		2026 and thereafter	No less than 25 each year

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 (RECs).
3. Each kWh of eligible energy generated within Missouri will count as 1.25 kWh.
4. The proposed initiative petition also requires solar rebate incentives to be provided by each utility beginning in 2014

Under the initiative petition the definition of "renewable energy" would no longer include Empire's Ozark Beach hydro facility. In order to meet the 2011 Missouri Renewable Portfolio Standard, renewable energy credits from Ozark Beach generation were retired, and the additional 0.25 bonus credits for Missouri-generated energy were claimed. If the pending initiative petition passes, Empire would not be able to use the energy credits from Ozark Beach for compliance.

In addition, if the proposed MORES initiative petition were to pass Empire would have to make significant changes to its current renewable energy compliance plan, which uses Empire's Ozark Beach hydro facility in conjunction with existing wind purchased power agreements (PPA) for compliance. Empire's current compliance plan also takes into consideration that its existing wind farm PPA's, Elk River and Meridian Way; expire in

2025 and 2028, respectively. As a result, Empire does not expect additions to its renewable portfolio, and associated costs, directly attributable to the current MORES until the 2026 timeframe.

Under the new MORES initiative petition Empire would see the cost increases associated with the solar rebate program as soon as 2014. In addition, Empire would see changes to its existing renewable energy portfolio beginning in 2024 and escalating substantially through 2032. The anticipated rate impact as a result of the pending initiative petition would begin in 2014, holding through 2023 and increasing from 2024 through 2026. During this period Empire would be restricted on the amount of incremental renewable energy due to the proposed rate cap, which limits rate increases to three percent on an annual basis for residential customers.

Since Empire is a multi-jurisdictional utility, it is subject to other states renewable energy standards as well. Kansas established a renewable energy standard effective November 19, 2010. It requires 10% of Empire's Kansas retail customer peak capacity requirements to be sourced from renewables by 2011, 15% by 2016, and 20% by 2020. In addition, there are several proposals currently before the U.S. Congress to adopt a nationwide renewable portfolio standard (RPS).

Empire has been selling the majority of the RECs it receives from the previously mentioned wind PPAs, and plans to continue to sell all or a portion of them moving forward. As a result of these REC sales, Empire cannot claim that the underlying energy is renewable. Once a REC has been claimed or retired, it cannot be used for any other purpose. At the end of 2011, sufficient RECs, including hydro, were retired to comply with the Missouri and Kansas requirements through the end of November 2011. Additional RECs were retired in January of 2012 to complete the process for 2011. In the future, Empire will continue to retain a sufficient amount of RECs to meet any current or future RPS.

5.5 Current Renewable Energy Standards Law Compared to a Portfolio Comprised Solely of Existing Resources with No Additional Renewable Resources

Analyze the levelized cost of energy needed to comply with the current Renewable Energy Standards law compared to the cost of energy resulting from a portfolio comprised solely of existing resources with no additional renewable resources.

With regards to the September 2010 IRP—the most recent IRP that Empire has filed—all of the plans in the study, including the preferred plan, comply with the current Missouri and Kansas Renewable Energy Standards (RES) based on the least cost planning approach. In other words, no plan had to be adjusted to meet the RES following the integration phase of the IRP process. The 150 MW Elk River wind farm PPA, the 105 MW Meridian Way wind farm PPA, and the Ozark Beach hydro unit allow Empire to comply with the RES for nearly all of the study period, and they are all *existing* resources. In fact, Empire's analysis shows that it complies with the current RES with aforementioned existing hydro and the existing PPA's through the 2026 timeframe.

Therefore, the levelized cost of energy needed to comply with the current RES law compared to the cost of energy resulting from a portfolio comprised solely of existing resources with no additional renewable resources, would be virtually identical in Empire's case.

5.6 Impact of Every State or Federal Fuel Source Subsidy

Disclose and discuss the amount and impact of every state or federal subsidy Empire expects to receive with regard to any or all fuel sources it intends to use during the IRP study period.

As previously mentioned, Empire receives energy from two wind resources through 20-year PPAs. Empire began purchasing energy from the Elk River wind farm in late 2005 and from the Meridian Way wind farm in late 2008. A federal production tax credit (PTC) for wind power was established to help stimulate investment in wind resources, and was available at that time. However, since Empire does not own these wind resources, Empire does not retain the PTC—the wind resource owners retain the tax benefits. In all alternate plans including the preferred plan, future wind PPAs were selected as proposed future resources, but none prior to 2017 (2018 in the preferred plan). The assumption used in Empire's 2010 IRP assumed that the PTC would expire by the end of 2012. Thus, no future federal subsidy for wind was utilized in the last IRP for future wind resources.

At this time, Empire has not established the fuel assumptions for the next triennial compliance filing scheduled for 2013. As a result, there are no known state or federal subsidies that Empire expects to receive with regard to any fuel sources at this time. To the extent that state or federal subsidies are utilized in the next IRP, they will be discussed in the 2013 IRP reports.