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2015 Integrated Resource Plan Annual Update Report

The Empire District Electric Company

File No. EO-2015-0216

March 2015

****Denotes Highly Confidential****

2015 Integrated Resource Plan Annual Update Report

Table of Contents

The Empire District Electric Company (Empire)
2015 Integrated Resource Planning (IRP) Update Report

1. 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-2013-0547 on July 1, 2013 (2013 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 with input from the Stakeholder Advisory Group established in Empire's 2010 IRP. This was Empire's first triennial compliance filing utilizing the revised Missouri IRP Rule. A Joint Filing, as required under 4 CSR 240-22.080(9), was made in EO-2013-0547 on January 31, 2014. Empire's most recent IRP annual update was filed in March 2014 in File EO-2014-0243 (2014 annual update). With this 2015 annual update, Empire will continue to inform Missouri stakeholders of ongoing IRP issues.

Another important aspect of this report will be to respond to five Special Contemporary Issues. As the Rule states, special contemporary issues involves a list of issues contained in a Commission order with input from staff, public counsel, and intervenors on new evolving industry 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. Each utility shall evaluate and incorporate special contemporary issues in its triennial compliance filing or annual update filing. The Order establishing the special contemporary resource planning issues for this filing was issued on October 22, 2014 in File No. EO-2015-0042 with an effective date of November 1, 2014

In addition to the periodic IRP analysis required by the Commission, Empire has an ongoing internal planning process. This internal planning process involves the creation of a rolling five-year business plan on an annual basis. Most of the updates in this IRP annual update will be based on Empire's most recent approved five-year business plan,

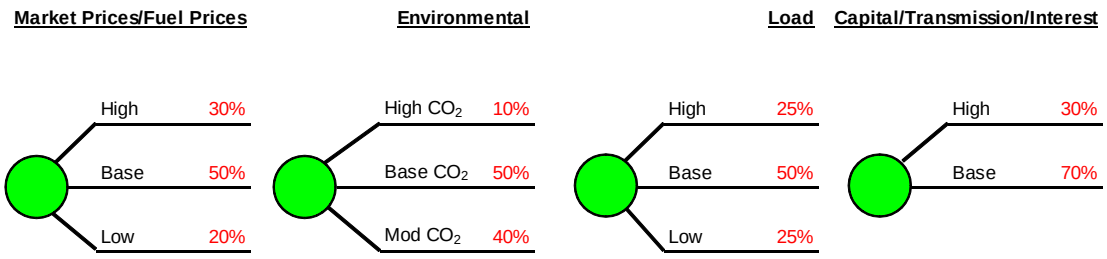
which is internally referred to as the five-year budget. The internal budget covers the period 2015-2019.

Following section (1) introduction, this report will contain sections addressing (2) the status of the critical uncertain factors, (3) a resource acquisition strategy update, (4) transmission and distribution analysis update, (5) other updates, (6) a preferred plan update and (7) special contemporary issues.

Empire's next triennial compliance filing is scheduled for April 1, 2016.

2. Status of the Identified Critical Uncertain Factors

In the most recent triennial filing (2013 IRP filing, most recent IRP, last IRP or recent IRP) Empire identified the following critical uncertain factors: environmental; market prices/fuel prices; load; and capital/transmission/interest rates. This section will address changes in these factors since the last IRP and the last annual update.



Environmental Update

In the 2013 IRP filing, the environmental analysis assumed three levels of future CO_2 (carbon) costs. The base case assumed there would be no carbon costs during the planning period. A moderate case assumed carbon costs would begin in 2021, and a high case assumed carbon costs would begin in 2015. Obviously, these long-term environmental assumptions will need to be reconsidered for the 2016 IRP. Special consideration will need to be given to recent environmental rule proposals concerning carbon regulation on existing power facilities which will be discussed later in this report. Empire's current five-year business plan which covers the period 2015 through 2019 does *not* include any carbon costs. This is still consistent with the 2013 IRP base case and Empire's preferred plan.

All of the alternate plans in Empire's 2013 IRP filing assumed costs for other emissions as required such as SO_2, NO_X and mercury. 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 2015 through 2019. However, Empire continuously evaluates the economics of purchasing allowances versus operating

its control equipment which could result in the purchase of minimal quantities of allowances in the future.

Environmental issues continue to be one of the leading factors facing the electric utility industry and resource planning. This report will provide an update on the following environmental issues that are among those that Empire continuously monitors.

- Clean Power Plan (Section 111(d) of the Clean Air Act)
- Clean Air Interstate Rule and the Cross-State Air Pollution Rule (CAIR/CSAPR)
- Mercury and Air Toxic Standards Rule (MATS)
- Ozone, particulate matter, National Ambient Air Quality Standards (Ozone/PM NAAQS)
- Clean Water Act (CWA)
- Coal Combustion Residuals (CCR)
- Surface Impoundments

Clean Power Plan (Section 111(d) of the Clean Air Act)

On June 2, 2014, the Environmental Protection Agency (EPA) released the proposed rule for limiting carbon emissions from existing power plants. The "Clean Power Plan" also known as Section 111(d) of the Clean Air Act, requires a 30% carbon emission reduction from 2005 baseline levels by 2030 and requires fossil-fuel fired power plants across the nation, including those in Empire's fleet, to meet state-specific goals to lower carbon levels. The EPA has identified four building block strategies to achieve the best system of emission reduction (BSER). Included in these strategies are the following: efficiency improvements at fossil fuel power plants; using lower-emitting sources (such as natural gas combined cycle units); using more renewables and keeping nuclear sources; and using power more efficiently. States will use the building blocks to craft their compliance plans or may work with other states in developing a regional approach to compliance, in which case additional time is given for implementation.

The EPA is scheduled to issue the final rule for existing power plants by summer of 2015. Each state must submit its initial compliance plan by summer of 2016 with additional time available by request until summer of 2017 for a single state or summer of 2018 for a multi-state approach. EPA received greater than 2 million public comments by the December 1, 2014 closure of the comment period. State, federal and industry representatives voiced their concerns with the regulation as written and the potential impact on electric grid reliability and the cost to implement. State and industry representatives including Empire continue to evaluate potential paths forward if the rule is finalized as proposed by the EPA.

Also, on June 2, 2014, the EPA released the proposed carbon pollution standards for modified and reconstructed stationary electric utility steam generating units (EGUs). The proposed rule focuses on electric utility steam generating units and natural gas-fired

stationary combustion turbines. The comment period ended October 16, 2014 and the EPA anticipates issuing a final rule in June 2015.

CAIR/CSAPR Update

The CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of SO2 and/or NOx in 28 eastern states and the District of Columbia, including Missouri, where Empire's Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and the Riverton Plant was not affected. Arkansas, where the Plum Point Plant is located, was included for ozone season NOx but not for SO2.

SO2 allowance allocations under the Title IV Acid Rain Program are used for compliance in the CAIR SO2 Program. The alternate plans in the IRP assumed costs for other emissions such as SO2, NOx and mercury. It was economically beneficial to purchase NOx Annual allowances in the final year of the CAIR Program (2014).

The CSAPR, beginning January 1, 2015, requires 23 states to reduce annual SO2 and NOX emissions to help downwind areas attain the 24-hour and/or annual PM2.5 (fine particle matter) NAAQS. Twenty-five states are required to reduce ozone season NOx emissions to help downwind states attain the 1997 8-hour Ozone NAAQS. The CSAPR NOx annual program impacts Empire's Missouri and Kansas units while the CSAPR NOx ozone season program impacts units in these two states plus Empire's unit in Arkansas.

The CSAPR divides the states required to reduce SO2 into two groups. Both groups must reduce their SO2 emissions in Phase 1. Group 1 states, which include Empire resources in Missouri and Arkansas, must make additional SO2 reductions for Phase 2 in order to eliminate their significant contribution to air quality problems in downwind areas. Empire's units in Kansas are in Group 2 of the CSAPR SO2 program.

Under the CSAPR Program, in the most current five-year business plan (2015-2019), which assumes normal operations while maintaining compliance with permit conditions, Empire anticipates that it will be economically beneficial to purchase allowances for some of these pollutants if needed. At the time of this writing the allowance markets have not been fully developed. However, Empire does not expect the cost of these allowances to be material should allowance purchases be required.

MATS Update

The MATS standard became effective in April 2012, and requires compliance by April 2015 (with flexibility for extensions for reliability reasons). For all existing and new coal-fired electric utility steam generating units (EGUs), the MATS standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply. On March 28, 2013, the EPA finalized updates to certain emission limits for new power plants under the MATS. The new standards affect only new coal and oil-fired power

plants that will be built in the future. The update does not change the final emission limits or other requirements for existing power plants. Empire's Environmental Compliance Plan is described in the 2013 IRP Executive Summary beginning on page 15. Empire has continued to move forward with the compliance of MATS. Empire's Air Quality Control System (AQCS) project at the Asbury Plant met successful completion of in-service testing in mid-December. This major environmental retrofit project will allow Empire to meet the EPA's new MATS Standards set to take effect in early 2015. It will also allow Empire to maintain a diversified fuel mix to the benefit of customers. The Asbury environmental retrofit project will be described later in this report.

Ozone/PM NAAQS Update

The NAAQS are standards established by the U.S. EPA under authority of the Clean Air Act (42 U.S.C. 7401 et seq.) that apply to outdoor air quality throughout the country. In January 2013, the EPA finalized the revised PM 2.5 primary annual standard at 12 ug/m3 (micrograms per cubic meter of air). States are required to meet the primary standard in 2020. The standard should have no impact on Empire's existing generating fleet because the regional ambient monitor results are below the PM 2.5 required level. However, the PM 2.5 standards could impact future major modifications/construction projects that require additional permits.

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds (VOCs) in the presence of sunlight. Based on the current standard, Empire's service territory is designated as attainment, meaning that it is in compliance with the standard.

CWA Update

Empire operates under the Kansas and Missouri Water Pollution Plans pursuant to the Federal Clean Water Act (CWA). Empire's plants are in material compliance with applicable regulations and have received all necessary discharge permits.

Riverton Unit 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. In 2007, the United States Court of Appeals remanded key sections of these CWA regulations to the EPA. The EPA suspended the regulations. Following a series of court approved delays; the EPA published the final rule on August 15, 2014 with an effective date of October 14, 2014. Court challenges are expected. Empire expects the regulations to have a limited impact at Riverton given the planned retirement of Unit 8 scheduled in 2016. A new intake structure design and cooling tower will be constructed as part of the Unit 12 conversion at Riverton. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. The new Iatan Unit 2 and Plum Point Unit 1 are covered by the proposed regulation, but were constructed with cooling towers, the proposed Best Technology Available. Empire expects them to be unaffected or minimally affected by the final rule.

CCR Update

In June 2010, the EPA proposed to regulate coal combustion residuals (CCRs) under the Federal Resource Conservation and Recovery Act (RCRA). In the proposal, the EPA presented two options: (1) regulation of CCR under RCRA subtitle C as a hazardous waste and (2) regulation of CCR under RCRA subtitle D as a non-hazardous waste. On December 19, 2014 the EPA finalized the requirements under the subtitle D solid waste provisions. Empire expects compliance with either option to result in the need to construct a new landfill and the conversion of existing ash handling from a wet to a dry system(s) at a potential cost of up to $15 million at the Asbury Power Plant. These preliminary estimates will likely change based on the final CCR rule and its requirements. Empire expects resulting costs to be recoverable in rates.

Surface Impoundments Update

Surface impoundment is the treatment, storage, or disposal of wastes in a lagoon or pond in order to prevent their escape into the environment. Empire owns and maintains a coal ash impoundment located at the Asbury Power Plant. Additionally, Empire owns a 12% interest in a coal ash impoundment at the Iatan Generating Station and a 7.52% interest in a coal ash impoundment at Plum Point. As a result of the transition from coal to natural gas fuel for Riverton Units 7 and 8 in September 2012, the former Riverton ash impoundment has been capped and closed. Final closure as an industrial (coal combustion waste) landfill was approved on June 30, 2014 by the Kansas Department of Health and Environment (KDHE).

On April 19, 2013, the EPA signed a notice of proposed rulemaking to revise its wastewater effluent limitation guidelines and standards under the CWA for coal-fired power plants. The proposal calls for updates to operating permits beginning in July 2017. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits, including permits for coal ash impoundments. Empire does not have sufficient information at this time to estimate additional costs that might result from any new standards. All of the coal ash impoundments are compliant with existing state and federal regulations.

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completed and was submitted to MDNR for review and approval on January 21, 2015. Receipt of the final construction permit for the waste landfill is expected in early 2016.

Market and Fuel Prices Update

This section will discuss natural gas prices, coal prices and market prices. A summary of the fuel price forecasts was presented in the 2013 IRP Executive Summary on pages 20-21, while the market price forecasts were described on pages 22-23. Additional information can be found in IRP Volume 4: the natural gas price forecasts can be found on pages 83-89; coal price forecasts can be found on pages 79-83; and the market price forecast information can be found on page 102. The 2014 IRP annual update report addressed these issues on pages 6-8.

Natural Gas Price Forecast Update

Natural gas prices can be influenced by a variety of factors and the prices can change daily if not hourly. For the long-range 2013 IRP study, Empire used the natural gas price forecasts from the Ventyx Spring 2012 Power Market Advisory database (considered highly confidential). Empire has not purchased a new long-range natural gas forecast since the 2013 IRP has been developed. However, for purposes of this update, Empire contacted Ventyx to inquire about natural gas price forecasts updates. Empire learned that Ventyx has developed its Fall 2014 reference case which contains a new natural gas price forecast that, on average over the next 20-years, is about 1% higher than the natural gas prices for the same period that were utilized in Empire's 2013 IRP. More specifically, this entails a near term reduction, but long term increase over the 2013 IRP natural gas price forecast. This is a revision to the 2014 IRP annual update. At that time, it was reported that on average over the next 20-years, natural gas prices would be about 2.7% *lower* than the natural gas prices for the same period that were utilized in Empire's 2013 IRP.

According to Ventyx, looking ahead to 2015-2016, declining forward natural gas prices are the result of the expectation of continued cost reduction in shale production, a queue of drilled but uncompleted wells that remains historically large coming online, and large volumes of associated gas production from natural gas liquids and tight oil production. From 2017 through 2022 a substantial revision to their outlook for liquefied natural gas (LNG) exports from North America increased the forecast price 35% whereas the spring 2012 increase was 21%. The Henry Hub forecast increases 35% from 2015 to 2020 as increasing demand combined with depletion of the cheapest portion of the resource base in several basins drive marginal prices higher. Prices are projected to increase to a relative plateau in the 2020s due to increased power generation demand and establishment of LNG export pathways. Production cost increases begin to accelerate in the late 2020s as a large tranche of lower cost shale reserves begin to be depleted. Retirements of coal and nuclear plants as well as load growth drive gas demand for power generation higher as well as gas prices in this period as well.

Coal Price Forecast Update

During each budget cycle Empire updates coal forecasts for internal planning purposes. This includes contract knowledge and input from those in charge of procuring coal for jointly-owned units as it becomes available. When the 2013 IRP was developed, coal price forecasts for owned units were based on the 2013-2017 budget cycle. The most recent five-year budget, however, is based on the more recent 2015-2019 budget cycle. Overall, the aggregate weighted average coal price is about 7.5% lower in the 2015-2019 budget as compared to the same period in the 2013 IRP as shown in the table below. The matching periods covered by the 2014 IRP annual update and the 2015 IRP annual update are very similar, as the aggregate weighted average coal price is about 1.4% higher in the 2015 IRP annual update as compared to the 2014 IRP annual update.

Weighted Average
Coal Price Comparison ($/MMBtu)

Year	2013 IRP Base Case	2014 IRP Annual Update	2015 IRP Annual Update
2015	2.14	1.93	1.93
2016	2.20	1.96	1.99
2017	2.24	2.03	2.07
2018	2.30	2.10	2.15
2019	2.38	--	2.29

With regards to coal prices, the following explanation from the 2014 annual update still applies to the 2015 annual update. In general, coal prices have declined in recent years due to lower demand for coal. The combination of relatively low natural gas prices, increasing generation of electricity from renewables and the lack of a strong recovery in electricity demand have all contributed to a surplus of coal, causing coal prices to decrease. In addition, new requirements to control emissions of mercury and acid gases have resulted in the retirement of some coal-fired generating capacity, contributing to a near-term decline in coal demand. Since there are no future coal units in any of Empire's 2013 IRP plans, this lower coal price forecast is not expected to impact capacity expansion planning.

Market Price Forecast Update

Market prices have a correlation with fuel prices, particularly natural gas prices. In the 2013 IRP, multiple sets of market prices were developed by Ventyx based on forecasted fuel prices, emission prices and other scenario assumptions. In order to develop market prices, Ventyx uses various modules to generate a forward market view of the Southwest Power Pool – Kansas/Missouri (SPP-KSMO) pricing hub by modeling the entire Eastern Interconnect, one of the major electrical grids in North America. The output is a set of 8,760 hourly market prices for each year in the study period. This process requires a

large amount of data and computer processing time. Empire has not contracted with Ventyx to generate updated long-term market prices since the 2013 IRP was developed. However, based on the preceding updated fuel price forecasts, it is assumed that the base market prices (apart from environmental assumption changes) would shift in relation to the updated natural gas price forecast. Market prices for the next IRP will need to consider the newly implemented SPP integrated marketplace (SPP IM) which began on March 1, 2014 and will be discussed later in this report.

Load Forecast Update

A summary of the 2013 IRP load forecast can be found in the Executive Summary on pages 10-14, and an entire 2013 IRP technical volume (Volume 3) is dedicated to load analysis and load forecasting. The load forecast section from the 2014 IRP annual update report appeared on pages 8-9. Since the 2014 annual update was filed in March, 2014 Empire has developed a new five-year load forecast for the Company's five-year budget covering the period 2015-2019. The 2013 IRP projected a summer peak of **_____** MW for 2015 without the impacts of new DSM. This compares to a 2015 projection of **____** MW from the 2014 annual update report, and a 2015 projection of **_____** MW from the new five-year load forecast. The latter two forecasts incorporate more recent energy efficiency trends. Each of these forecasts display modest growth with annual peak and energy growth rates less than one percent during the five year period. The most recent forecast shows a slight year over year annual peak growth and an annual energy growth rate under a quarter of one percent.

Empire's electric customer count has now exceeded the pre-tornado (May-2011) level. Following the tornado it took about two and a half years to reach this point. The actual 2014 peak demand of 1,162 MW occurred in the month of January, marking the third time in the past 25 years that Empire has had its annual peak occur during the winter season and the second time in the past five years. Empire is somewhat different than many of the other electric utilities in the region in that it has dual (winter/summer) system peaks almost equal to each other. Empire has a winter/summer peak demand ratio over the past 15-years of about 94 percent. In the past Empire's winter peak can exceed the summer peak in years with very cold winters and milder than normal summers.

The following tables compare the demand and energy forecasts from the 2013 IRP, the 2014 annual update and Empire's current five-year budget. The five-year budget's short-term forecast covers the period 2015-2019 and incorporates recent economic and efficiency trends and the Company's field knowledge regarding potential expansions and reductions over that period. This includes the new Mercy Hospital, an 890,000 square foot facility that is expected to open in late March 2015; and the new Joplin High School and Franklin Technology Center, encompassing 480,000 square feet, which opened in early September 2014. Although there are parcels of land within the tornado zone still undeveloped, the City of Joplin is continuing to progress towards its pre-tornado state, building back better and more energy-efficient than ever.

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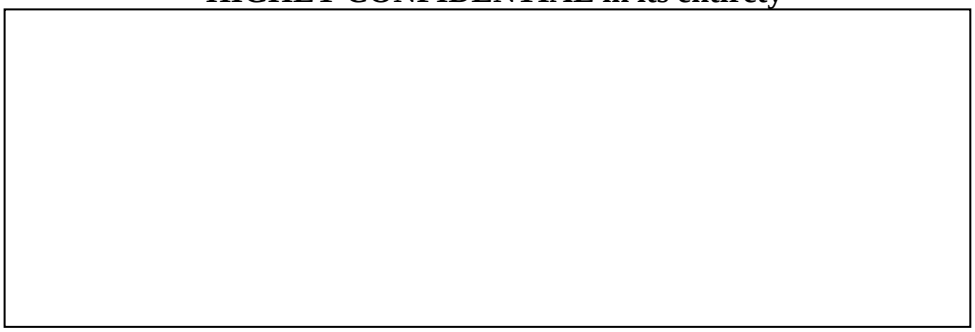

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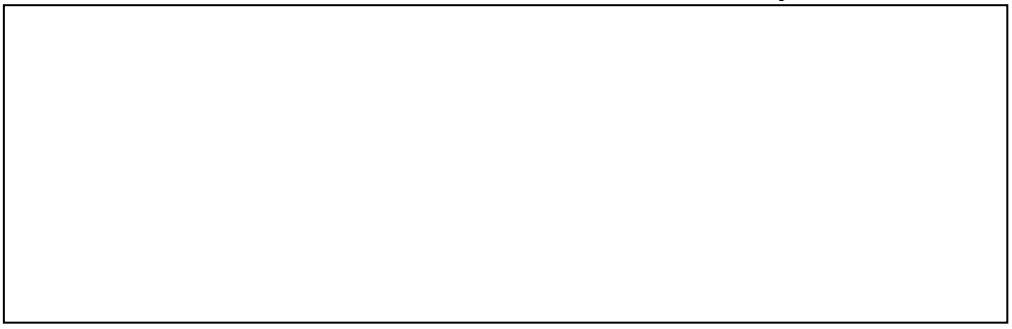


Capital Costs and Interest Rates Update

After reviewing the long-term planning interest rates and capital costs for generic resources in the 2013 IRP, it has been determined that there are no updates to report at this time. Empire will reevaluate the capital costs and all other planning assumptions during the development of the 2016 IRP filing.

With the Asbury AQCS and turbine retrofit projects now in service, the next major construction project, currently underway, is the conversion of the existing Riverton Unit 12 simple cycle combustion turbine to a combined cycle unit, with an expected completion in mid-2016. This project has a cost estimate in the range from $165 million to $175 million (without AFUDC). This is the same cost estimate for this project that was reported in the 2014 IRP annual update.

3. Resource Acquisition Strategy Update

Empire has made progress in implementing the resource acquisition strategy that was outlined in the 2013 IRP. The most significant updates include the Asbury AQCS and turbine retrofit projects entering service and the status of the demand-side portfolio implementation which is currently a part of the MEEIA filing (EO-2014-0030). This report will provide an update on the following implementation items:

- Asbury air-quality control system (AQCS)
- Asbury turbine retrofit project
- Riverton projects
    - Riverton Units 7, 8 and 9
    - Riverton Unit 12 combustion turbine (CT) conversion to combined cycle (CC)
- Demand-side management (DSM)

Asbury Air-Quality Control System (AQCS)

Asbury Unit 1 was installed in 1970. This wholly-owned coal-fired unit is located near Asbury, Missouri. As reported in the 2013 IRP, in order to comply with current and forthcoming environmental regulations, the plant underwent a major construction project to retrofit the unit with environmental equipment including the installation of a scrubber, fabric filter and powder activated carbon injection system (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. Total project costs through the end of 2014 were approximately $110.9 million. The Asbury AQCS entered service on December 15, 2014, and performance testing to determine whether it meets performance guarantees was performed in February, with results still pending. Selective catalytic reduction (SCR) for nitrous oxides (NOx) control was completed in 2008.

Asbury Turbine Retrofit Project

During Asbury's fall 2014 outage, during which the tie-in of the new AQCS was performed, the Asbury Unit 1 turbine's inner cylinders and rotors were replaced. These components utilize a newer design, increasing efficiency and capacity. This additional capacity will partially offset the capacity lost due to the retirement of Asbury Unit 2 and due to the additional auxiliary loads imposed by the AQCS. The turbine was tested on November 21, 2014, and the increase in electrical output exceeded the increase guaranteed by the contractor.

Asbury Project Update

An implementation plan for the Asbury project was included in the 2013 IRP Executive Summary on page 41 and was updated in the 2014 annual update on page 11. Since the 2014 IRP Annual Update Report was filed, the Asbury project reports the following updates:

- Project is nearing completion
    - Mechanical Completion achieved September 12, 2014
    - AQCS tie-in outage completed and unit back on-line November 5, 2014
    - First scrubbing on November 8, 2014
    - In-service testing completed December 15, 2014
    - Substantial Completion achieved December 16, 2014

  - Performance testing performed in early February 2015
- Permitting activities for the new Asbury landfill remain on schedule

Riverton Project

The Empire Environmental Compliance Plan (see the 2013 IRP Executive Summary pages 15-16) to comply with forthcoming and recent environmental regulations also includes projects at the Riverton generating station. This includes recent operational changes, the retirement of Unit 7 and the eventual retirement of Units 8 and 9; and the conversion of Unit 12 to a combined cycle unit.

Riverton Units 7, 8 and 9

Riverton Unit 7, now retired, and Riverton Unit 8 operated for nearly 60 years as small coal-fired units. Unit 7 was rated at 38 MW and was installed in 1950. Unit 8 is rated at 54 MW and was installed in 1954. Both units were transitioned to operate solely on natural gas on September 18, 2012. Due to a failure of its main generator step-up transformer, Riverton Unit 7 was retired from service on June 30, 2014. This was approximately two years earlier than what was originally planned and reported in the 2013 IRP. Due to the significant capital expenditures required to return the unit to service, it was determined that the retirement of the unit was the most cost effective option. At the time of its retirement, Riverton Unit 7 was about 64 years old. It had not operated since its transition to natural gas only operation. A letter to notify the Commission regarding the retirement of Riverton Unit 7 was filed in the 2013 IRP case (EO-2013-0547) on August 8, 2014 in accordance with 4 CSR 240-22.080 (12). Empire does not view this change in the timing of the resource's retirement as a significant change in its operation, but chose to notify the Commission and IRP stakeholders for informational purposes. No change was made to Empire's preferred plan and acquisition strategy as a result of this action.

Riverton Unit 8, along with Riverton Unit 9, a small combustion turbine that requires steam from the Unit 8 boiler for start-up, will be retired upon the conversion of Riverton Unit 12, a simple cycle combustion turbine, to a combined cycle unit. The conversion of Riverton Unit 12 and retirements of Riverton Units 8 and 9 retirements is currently scheduled for mid-2016.

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 electrical transmission were designed and built to accommodate its conversion to a combined cycle unit at some point in the future. The Riverton Unit 12 combined cycle conversion will add about 100 additional MW to the existing capacity of Unit 12, making the Riverton

combined cycle around a 250 MW unit upon completion. As mentioned, this will coincide with the planned retirement of Riverton Units 8 and 9. The Riverton Unit 12 combined cycle conversion will utilize existing site infrastructure and will incorporate the existing Riverton Unit 12 combustion turbine as part of the 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. As previously mentioned, the project is expected to be complete by mid-2016.

Riverton Project Update

An implementation plan for the Riverton project was included in the 2013 IRP Executive Summary on pages 40-41 and updated in the 2014 annual update on page 12. Since the 2014 IRP Annual Update Report was filed, the Riverton project reports the following updates:

- Major construction commenced May 2014
- Major equipment procurement complete
- Foundations completed, HRSG casing and modules installed, large transformers installed on foundations, generation building structural steel complete
- Cooling tower, generation building exterior and generation building interior rooms in progress
- Deliveries of major equipment (HRSG, large power transformers, steam turbine generator, condenser) completed early February 2015
- Turbine centerline equipment set in place late January/early February 2015
- Project remains on contractual milestone schedule

Demand-side Management (DSM) Implementation Plan Update

Perhaps the most significant change to the 2013 IRP implementation plan concerns the implementation of the preferred plan's demand-side resource portfolio which is related to an agreed to follow-on filing under the Missouri Energy Efficiency Investment Act of 2009 (MEEIA). In the Executive Summary of the 2013 IRP on pages 41-42, Empire stated the following:

> "The [demand-side resource] implementation may be modified, depending on the outcome of this [2013] IRP and subsequent MEEIA filing. There is a level of uncertainty surrounding the MEEIA filing, including the Commission's approval of the DSM portfolio and the recovery of DSM costs and benefits. This uncertainty could impact the DSM implementation timeline and Empire's ability to move forward with the proposed DSM Portfolio. Due to the uncertainty around the upcoming MEEIA filing, Empire's DSM implementation schedule will remain flexible."

Empire's MEEIA filing was made as planned on October 29, 2013 (2013 MEEIA) in File No. EO-2014-0030, but the procedural schedule has been suspended. In this instance, the previous excerpt from the 2013 IRP report about uncertainty surrounding Empire's MEEIA filing has proved to be correct. In the meantime, Empire continues to offer a portfolio of Energy Efficiency programs to its eligible Missouri retail customers (established in 2006). Empire updates the Missouri stakeholders about the existing demand-side programs periodically through the Stakeholder Advisory Group meetings.

In the 2014 annual update report—filed about three and a half months after the 2013 MEEIA filing (EO-2014-0030) — Empire referenced changes made to the implementation schedule presented in the DSM volume of the 2013 IRP. Since that time, additional changes have been considered for Empire's 2013 MEEIA portfolio, both in scope and in the implementation schedule. With the MEEIA filing's procedural schedule suspended to allow for additional consulting and discussions between Empire and its stakeholders, it was agreed that Empire would revise its 2013 MEEIA portfolio for further consideration and to ensure it was reasonably achievable. Following stakeholder input and consultant updates, Empire removed three program offerings from its proposed portfolio, which retains roughly 75 percent of the estimated annual energy savings, while shedding about 55 percent of the costs, making the overall proposed portfolio more cost effective. Of the eight retained programs, six are already being offered in Empire's existing Missouri energy efficiency portfolio, and variations of the other two programs are currently being offered by Empire in its Arkansas jurisdiction. At the request of some of the stakeholders, Empire used this updated and more streamlined portfolio in an IRP type integration analysis, with additional updated planning assumptions. This analysis also showed that the updated portfolio of eight programs was more cost effective than the 2013 IRP/MEEIA portfolio. Throughout the process, the proposed implementation target has continued to shift since no agreement has been reached in the 2013 MEEIA case. At this time, the future of the 2013 MEEIA portfolio remains unclear.

4. Transmission and Distribution (T&D) Analysis

In the Joint Filing required under 4 CSR 240-22.080(9) of the IRP Rule that followed the review of the 2013 IRP, Empire agreed to perform a comprehensive analysis of advanced distribution technologies in its transmission and distribution analysis section of the 2015 annual update report, and in its next triennial compliance filing. This section of the report will update stakeholders about Empire's T&D system, reliability efforts—including Operation Toughen Up, a long-term initiative currently in progress to strengthen the T&D delivery system—and provide an update about advanced distribution technology evaluations. The information in this section of the report, consistent with the scope of an IRP annual update, serves as a starting point for further analyses in the 2016 IRP.

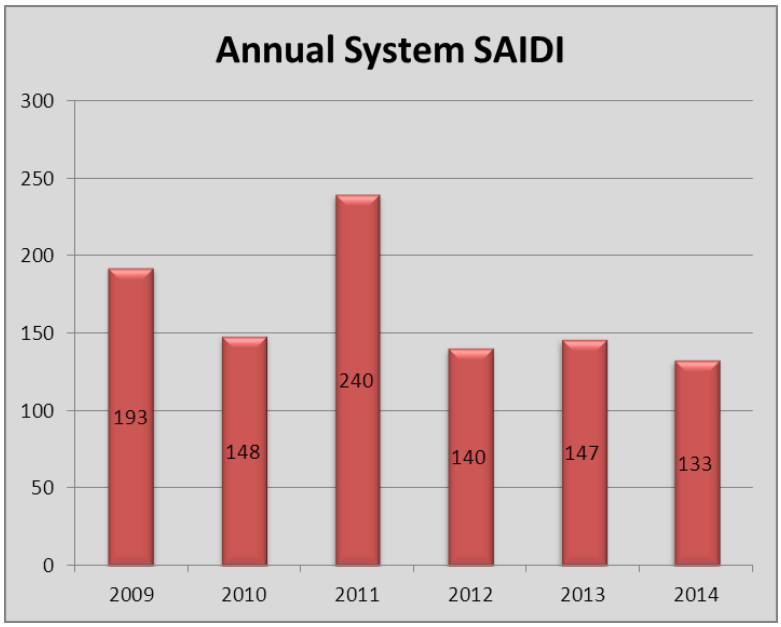
Empire's transmission and sub-transmission systems consists of approximately 22 miles of 345kV owned line, 441 miles of 161kV operated line, one span of 138kV operated line, 745 miles of 69kV operated line and 81 miles of 34.5kV operated line. Empire's

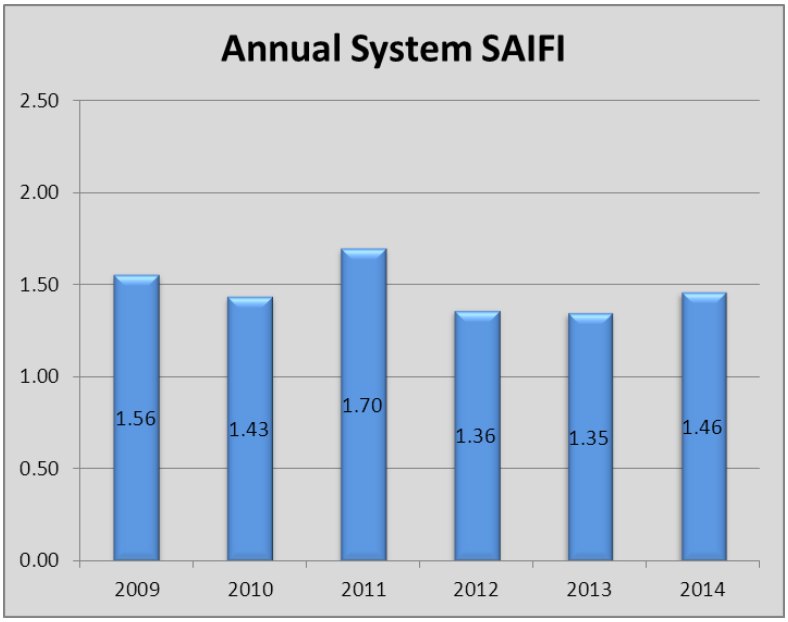
distribution systems encompass approximately 6,141 miles of overhead construction and an additional 770 miles of underground construction. The distribution systems within Missouri represent approximately 83% of Empire's distribution networks. Empire's transformer characteristics include approximately 301 station transformers of which 36 are between 0 to 9 years of age; 38 are between 10 to19 years of age; 62 are between 20 to 29 years of age; 43 are between 30 to 39 years of age; and 122 are greater than 40 years of age. Empire has 70 station transformers connected to the 161kV system, 159 station transformers connected to the 69kV system and 50 transformers connected to the sub-69kV systems (34.5kV, 25kV, & 12kV networks for varying applications). Distribution networks encompass approximately 95,500 service transformers of which, 86,000 or about 90% of the system total serve the Missouri portion of the Empire service territory.

Empire's electric metering is comprised of approximately 221,202 meters, of which approximately 206,000 or about 93% are located in the Missouri jurisdiction. The average age of the electric meters installed on Empire's system is approximately 22 years—this represents an average of the date installed weighted to the percentage that each manufacturer represents for the total system.

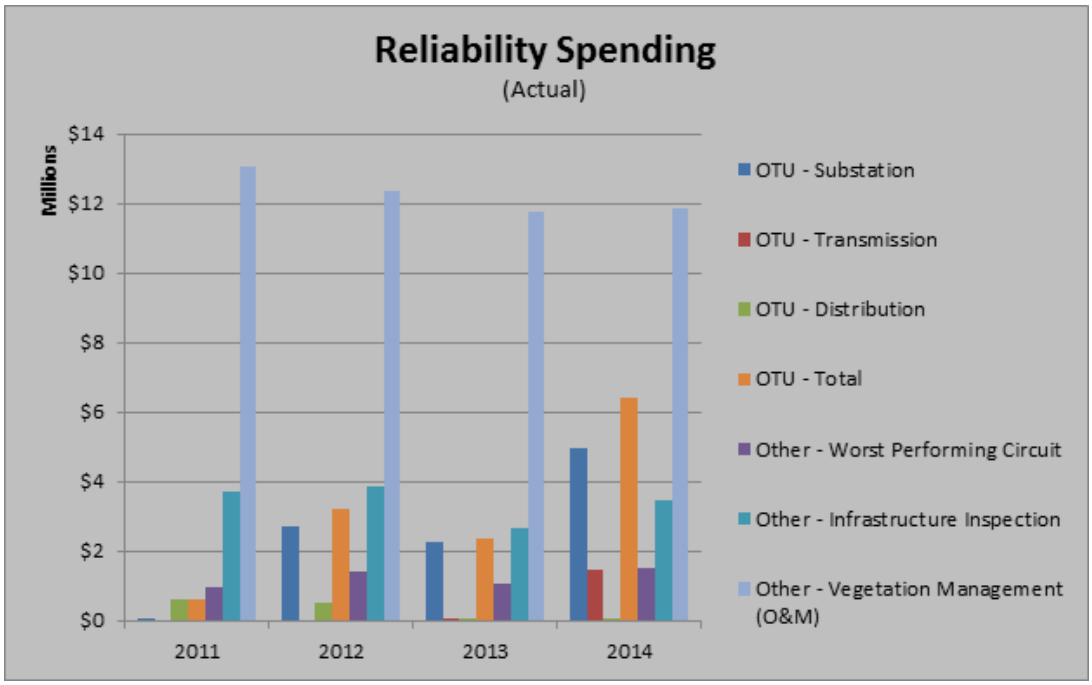
Operation Toughen Up (OTU)

As described in the 2013 IRP Executive Summary on pages 24-25 and the 2014 annual update report on pages 14-15, Operation Toughen Up is a long-term $100 million initiative currently in progress to strengthen the transmission and distribution (T&D) delivery system. Since reliable service is important for customers, Empire has established long-term goals to address two primary factors – interruption frequency and interruption duration. These factors are measured by the reliability indices SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). One project completed this year in conjunction with Operation Toughen Up was the rebuilding of 27 miles of transmission line in the Welch, Oklahoma, and Chetopa, Kansas, areas. Also to ensure reliable service, Empire continued the annual transmission line inspection to identify potential issues with structures, hardware, conductors, vegetation and line clearance. This provides the opportunity to address situations before they become problems enhancing reliability to customers. As a result of the aforementioned initiatives and other additional reliability focused projects, the SAIDI rate dropped to 133 minutes, about a ten percent improvement over 2013. Empire will continue to work toward long-term goals to achieve a SAIDI of 100 and a SAIFI of 1.00.





As shown in the graph below, Empire has made significant investments in reliability over the past few years. The graph below highlights T&D reliability spending in the Operation Toughen Up (OTU) and other categories.



The Empire Reliability Team has already identified locations for future sectionalization, reconductoring and supervisory control and data acquisition (SCADA) projects. There are ten substation breaker projects and six automatic transfer switch projects scheduled through 2020. The Reliability Team regularly visits with local operations managers to identify potential reconductor sites. Eight reconductor sites have been scheduled in 2015. The Reliability Team is also working to incorporate at least two distribution SCADA projects into each year to expand the data acquisition and fault study capabilities across the system. The Reliability Team continues to evaluate emerging technologies and works to better understand the root cause of interruptions so that more effective solutions may be identified.

Advanced Distribution Technology Evaluations Update

As stated in the 2013 IRP, the previously employed/evaluated advanced technologies include automated distribution transfer schemes, advanced recloser controls, fuse coordination programs, Optical Ground Wire (OPGW), all-dielectric self-supporting cables (ADSS), microprocessor relaying schema, redundant protective relaying on transmission line panels, and automatic transfer schemes on the 69kV transmission systems. In support and furtherance of advanced distribution technologies on Empire's system, the Company continually evaluates avenues to improve reliability with minimal rate impact in order to better serve its customers. Empire strives to strike a balance between vetting, evaluating, and implementing emerging technologies for the benefit of customers. One hindrance to the requirement of evaluating "advanced technologies" is the ambiguity of how advanced distribution technologies are defined within the industry. Without definitive cost/benefit ratio tests or resolute definitions as to what is considered

an advanced distribution technology, it is difficult to perform the evaluation process. Even so, Empire has proceeded with a focused evaluation as to how the transmission and distribution systems may operate more efficiently and achieve lower cost to the customers. Various applications have been reviewed internally and subsequent pilot programs have been initiated. A list of the advanced technologies presently being evaluated follows, including associated costs, benefits, and results of ongoing or past evaluations.

The Following technology evaluations are

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HIGHLY CONFIDENTIAL IN ITS ENTIRETY

The above technologies exhibit a focused effort on substation equipment. This focus was of particular priority due to the long lead times of possible equipment failures and the wide-ranging outage impacts to a large number of customers in the event of equipment failures. Empire deemed such a focus merited in an attempt to realize the most cost effective and most reliable solutions for customers. Further investigation as to the

utilization of these systems as well as future technologies should yield a more robust electrical network to serve Empire's customers.

Although Empire has invested in and piloted various advanced technology applications, there is a limit to the accrued benefit customers will actually realize. Spending on emerging technologies can be boundless. Empire has attempted and will continue to strive for a healthy balance of vetting newly emerging technologies in parallel with time proven implements. The benefits of the piloted projects are presently being weighed against their associated costs to implement/deploy, however benefits of such programs are very difficult to ascertain. For example, regardless if a transformer monitor is installed and a failure occurs, the result would still be an outage to a large number of customers. Alternatively, if the dissolved gas monitoring or DGM program is implemented system-wide and transformer failures subside, the metrics to attribute the reduction in outages to a particular device or strategy are very difficult to apportion among other initiatives across the company. At this time, without clarity as to which metrics should be utilized and given the high number of unproven technologies, "advanced technology" benefits are very difficult to quantify. These aspects in concert with concerns about the impact on customer rates give rise to a difficult path of evaluating and implementing emerging T&D technologies. Empire will continue to examine advanced technologies in an attempt to best balance cost versus benefits.

5. Other Updates

This section of the 2015 IRP Annual Update Report will provide updates to other IRP related issues, or what the IRP Rule refers to as "changing conditions generally."

Plum Point Purchase Power Agreement (PPA) Update

The Plum Point Energy Station (Plum Point) is a 670-megawatt, coal-fired generating facility located near Osceola, Arkansas. The unit became commercially available on September 1, 2010. Empire owns, through an undivided interest, 50 megawatts or 7.52 percent of the unit's capacity. Empire also has a long-term (30-year) agreement for the purchase of an additional 50 megawatts (MW) of capacity from Plum Point. The end date of the PPA agreement is August 31, 2040. Empire has the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015. This purchase option was evaluated as part of the 2013 IRP. It was described in the 2013 IRP Executive Summary on page 17 and in the 2014 annual update on page 15. In previous reports, Empire has stated that while it was not Empire's intention to exercise the option in 2015, the Company would continue to evaluate this purchase option through the exercise date as well as explore other options with the purchase power agreement holder, Plum Point Energy Associates (PPEA), related to the timing of this option. Empire has now further considered this option.

In early 2015 Empire updated the economic analyses related to the breakeven price per kW to purchase the additional 50 MW of Plum Point. In addition to an economic

analysis, other factors were also considered. The economic analyses were updated to account for updated assumptions such as carrying charge rate, discount rate, fuel prices, operation and maintenance (O&M) costs, capital costs and environmental costs since the 2013 IRP was developed. Four cases were studied. Two cases involved replacing the Plum Point PPA when it expires in 2040 with a similar coal PPA (which may or may not be a viable option in the future), and two cases considered a natural gas-fired combined cycle replacement. The uncertainty of how a future coal PPA would be structured and the uncertainty of future carbon regulations were considered. The modeling produced a range of $1,820/kW to $2,782/kW for Empire to breakeven on the investment, with an expected value of approximately $2,300/kW based on weighting the four cases. In other words, Empire would have to purchase at or below $2,300/kW in order to breakeven, prior to considering other factors.

Plum Point PPA Conversion to Ownership Other Factors

The other factors include plant ownership structure, availability restrictions due to location, capacity factor, transmission delivery costs, and future environmental policies. Empire reviewed the unit's availability history, PPA guarantees (the PPA has availability and heat rate guarantees that are not extended to ownership), the Environmental Protection Agency's (EPA) proposed Clean Power Plan and the increased transmission delivery costs due to the location of Plum Point in the Entergy system and their participation in the Midcontinent Independent System Operator (MISO). Empire's current diversity of Plum Point ownership and Plum Point PPA mitigates some of the "other factor" risk. Therefore, consideration of these other factors favors the continuation of the current Plum Point PPA rather than converting it to ownership.

Plum Point PPA Conversion Ownership Conclusion

While Empire intends to maintain an ownership interest in the plant for the life of the asset (i.e. well in excess of 30-years), risks of taking on an even larger ownership interest in the plant was thoroughly considered. Risk factors such as plant ownership structure, availability restrictions due to location, capacity factor and future environmental policies—particularly related to greenhouse gas emissions, make this plant unique when compared to Empire's other singly- and jointly-owned units. Empire weighed the risks and costs associated with increased ownership, as well as the components of the purchase price, versus the guarantees and costs allowed in the PPA. As a result of the economic analyses, the consideration of the other factors and other capital projects Empire is undertaking in the same timeframe, Empire will not execute the option to purchase the 50 MW of Plum Point currently under PPA in 2015. This is consistent with the 2013 IRP preferred plan.

Renewable Energy Standard (RES) Update

Empire reported on the RES in the 2013 IRP Executive Summary on pages 17-18 and in the 2014 Annual Update Report on pages 15-16. Empire has been in compliance with all RES regulatory requirements in Missouri and Kansas as a result of purchased power

agreements with the Elk River Wind farm (150 MW) located in Butler County, Kansas and the Meridian Way Wind farm, (105 MW), located in Cloud County, Kansas. Currently about 15% of Empire's native load is provided by these wind resources (with a portion of the renewable attributes sold via renewable energy credits (RECs)).

As reported in the 2013 IRP and 2014 annual update, the Missouri regulations require that 2% of the energy from renewable energy sources must be solar and that Empire has been exempted by statute from the solar requirement. Since the Missouri RES has been in place, several legal challenges have been raised to Empire's statutory exemption from the solar requirement. On February 10, 2015 the Missouri Supreme Court overruled the solar rebate exemption that was extended to Empire in 2008. At this time, Empire has asked for reconsideration. It is Empire's understanding that this process could take several months.

Empire does not currently offer rebates for solar installations by customers due to the previously mentioned exemption from the solar requirements of Proposition C. Additionally, all services offered by Empire must be in accordance with the tariffs on file with the Missouri Public Service Commission, and Empire does not have an approved tariff governing solar rebates. Once there is a final decision from the court and the Commission, Empire will take whatever steps may be necessary to comply with their decisions.

Empire continues to monitor RES issues, including potential changes to RES requirements at the state and federal levels.

The Southwest Power Pool (SPP) Integrated Market Place (IM) Update

In March of 2014, the Southwest Power Pool's (SPP) Integrated Marketplace began operation. As a member of SPP, this changed the way Empire does business. Empire now submits its generation into the SPP market on a daily basis and the SPP market determines the most economical and reliable solution for providing energy to customers. Empire had anticipated a cost savings from the SPP IM, and to date this is proving to be accurate. Customers are beginning to see the benefit of the SPP IM directly through the fuel cost they pay.

The SPP IM has been considered a success through its first year of operation. A reduction in production costs resulting from the regional commitment and dispatch is evident by the reduction in online capacity to serve load. Additionally, the ancillary service market has reduced the amount of spinning and supplemental reserves required, thereby allowing for a more efficient use of generation resources. Empire's internal analysis has estimated that production costs from March 1, 2014 through December 31, 2014—the first ten months of the market—have been reduced by approximately 3.3% as a result of the SPP IM versus the pre-SPP IM model which included the now defunct SPP energy imbalance services (EIS).

Demand-Side Management (DSM) Update for Arkansas, Oklahoma and Kansas

This section of the 2015 IRP Annual Update Report will provide an update on Empire's DSM efforts in its Arkansas, Oklahoma and Kansas jurisdictions.

Arkansas DSM

Empire serves about 4,400 customers in northwest Arkansas. Besides Missouri, Empire's largest jurisdiction, Arkansas is the only other jurisdiction where Empire offers demand-side programs. The current demand-side portfolio contains ten residential programs and three commercial and industrial (C&I) programs. Empire has offered customer programs in Arkansas since October 2007. Recently Empire has been working as part of a group referred to as the Parties Working Collaboratively (PWC)—a group of Arkansas investor-owned utilities (IOU) and stakeholders. Per Arkansas Public Service Commission Order, the PWC spent much of the year developing a plan for a statewide unified approach to weatherization and to C&I programs. The PWC also solicited the consulting firm Navigant to conduct a statewide DSM Potential Study, which would cover all seven of the state's IOUs.

Due to the small customer count, the rural nature of Empire's Arkansas service territory and other factors, it has been very difficult for Empire to meet the state energy efficiency goals. Despite the acknowledged difficulties surrounding the successful implementation of energy efficiency programs in its Arkansas territory, Empire continues to make improvements. In 2012, 2013, and 2014, Empire reported increases in participation in nearly all of its energy efficiency programs in Arkansas. These achievements were highlighted by Empire's residential contractor weatherization program, which debuted in the fourth quarter of 2013. This is an Empire weatherization program that is separate from the statewide weatherization program. To date, this program has made cost-effective improvements to nearly 50 severely inefficient homes in Empire's Arkansas territory.

Oklahoma DSM

Empire serves about 4,700 customers in northeastern Oklahoma and began an offering of four customer programs in early 2010. On May 1, 2014, Empire received Order No. 624718 in Oklahoma Corporation Commission Cause No. PUD 201300203 approving its request to terminate its energy efficiency portfolio and cost-recovery rider, pending the refund of any over-recovered amount. This action was taken due to the jurisdiction's small customer count, rural nature of the service territory, historically low participation levels and the economic burden on the Oklahoma customers. As of the date of the Order, Empire no longer offers its energy efficiency programs in Oklahoma, and has since discontinued its DSM Rider for cost recovery.

Kansas DSM

Empire serves nearly 9,700 customers in southeast Kansas. Empire began a Kansas demand-side energy efficiency pilot program in June 2010. This pilot program expired on June 30, 2013 and was not renewed. Following the discontinuation of its energy efficiency portfolio in 2013, Empire discontinued its Energy Efficiency Rider, which had achieved a full refund of over-recovered DSM funds, in January 2015.

Indigenous Wind, Agricultural Residues, Poultry Waste and Landfill Gas Update

Empire has investigated the utilization of indigenous wind, agricultural residues, poultry waste and landfill gas in its service territory. At the present time, there are ten demand-side net-metered wind resources in Empire's service territory. All of these wind resources are located in Missouri. Eight are residential and two are commercial installations, with a total nameplate capacity of about 111.8 kW. Empire has 255 MWs of supply-side wind resources in its generation portfolio via long-term purchased power agreements. These wind farms are located in Butler and Cloud counties in Kansas and are outside of Empire's service territory. Currently they provide about 15% of Empire's native load energy requirements. Since these wind PPAs expire post-2025, Empire has not investigated potential utility scale indigenous wind sites at this time.

There are no known substantially-sized generating resources in the service territory related to agricultural residues, poultry waste and landfill gas. Empire provides electric service to four relatively large poultry processing plants and to two large feed mills. There are several small independently-owned poultry producers in and around Empire's service area. A review of the potential landfill gas maps shows a couple landfills located in or near Empire's service territory. The Wheatland landfill is located in rural Cherokee County Kansas and the Newton McDonald landfill is located near Neosho, Missouri.

At this time, Empire has not determined the viability or cost-effectiveness of these types of resources, but Empire will conduct a more detailed analysis of favorable indigenous energy resources in the 2016 IRP.

6. Preferred Plan Update

The 2013 IRP preferred plan was described in the Executive Summary on pages 36-39 and was updated on pages 18-22 of the 2014 Annual Update Report. The preferred plan near-term highlights since the 2013 IRP was filed including the IRP and MEEIA filing dates can be summarized as follows:

- July 1, 2013 – 2013 IRP filed
- October 29, 2013 – MEEIA filed
- Late 2013- to present – MEEIA discussions in File No. EO-2014-0030
- December 31, 2013 – Asbury Unit 2 coal unit retired

- January 14, 2014 – Order issued granting the motion to suspend the procedural schedule in the MEEIA case
- March, 2014 – 2014 IRP Annual Update Report filed
- April, 2014 – 2014 IRP Annual Update workshop
- June 30, 2014 – Riverton Unit 7 retired from service
- December 15, 2014 – Asbury Unit 1 AQCS and turbine retrofit projects enter service
- March-April 2015 – the 2015 IRP Annual Update Report and Workshop
- April 2016 – next IRP triennial compliance filing scheduled
- Mid-2016 – complete the Riverton Unit 12 simple cycle gas turbine conversion to a combined-cycle unit (expected to add about 100 MW) and retire Riverton Units 8 and 9

As discussed in the Resource Acquisition Strategy Update section of this report, the supply-side resources in the preferred plan for the period 2015-2019 are moving forward as planned. The only preferred plan update with regard to the supply-side projects is the Riverton Unit 7 retirement mentioned earlier. At this time the only other update to the 2013 IRP preferred plan is in regard to the DSM implementation and the related MEEIA filing.

Riverton Unit 7 Retirement

In an earlier section that described Riverton Units 7, 8 and 9; the Riverton Unit 7 retirement was discussed. After about 64 years of service, this unit was retired from service on June 30, 2014 due to a failure of its main generator step-up transformer while returning the unit from a scheduled outage. This retirement was approximately two years earlier than what was originally planned and reported in the 2013 IRP. However, Empire does not view this as a significant change in its operations nor a significant departure from the 2013 IRP preferred plan. The 38 MW unit had not operated since it had transitioned to natural gas only operation in September 2012. On August 8, 2014 in accordance with 4 CSR 240-22.080 (12), Empire filed a letter in the 2013 IRP case to notify the Commission and IRP stakeholders about the unit's retirement for informational purposes. No change was made to Empire's preferred plan and acquisition strategy as a result of this action.

Demand-Side Management Preferred Plan Update (as of March 2015)

At the time of this IRP annual update filing, the 2013 MEEIA procedural schedule has been suspended and the 2013 MEEIA case has not achieved a resolution. Instead of the 2013 IRP/MEEIA demand-side portfolio proposed by the 2013 IRP preferred plan, Empire is still offering its pre-MEEIA portfolio of demand-side programs to its eligible Missouri retail electric customers.

Following the 2013 IRP, Empire made its 2013 MEEIA filing as planned on October 29, 2013 in File No. EO-2014-0030. During various technical conferences with stakeholders,

cost-effectiveness, implementation schedules, portfolio composition, program goal achievement, demand-side investment mechanisms and other issues have been discussed. The following tables help summarize Empire's Missouri demand-side portfolio discussions. The first table represents Empire's existing demand-side portfolio that is currently being offered to eligible customers. The second table shows Empire's proposed 2013 IRP/MEEIA demand-side portfolio as filed, and the third table shows the revised 2013 MEEIA demand-side portfolio that was proposed following stakeholder discussions.

Existing Missouri Demand-Side Portfolio	
Program	**Annual Budget**
ENERGY STAR® New Homes Program	$338,800
High Efficiency AC Rebate Program	$382,000
Home Performance with ENERGY STAR® Program	$115,000
Low-Income New Homes	$10,500
Low-Income Weatherization	$226,430
Building Operator Certification	$34,500
Commercial & Industrial Rebate Program	$414,000
Total Portfolio	$1,521,230

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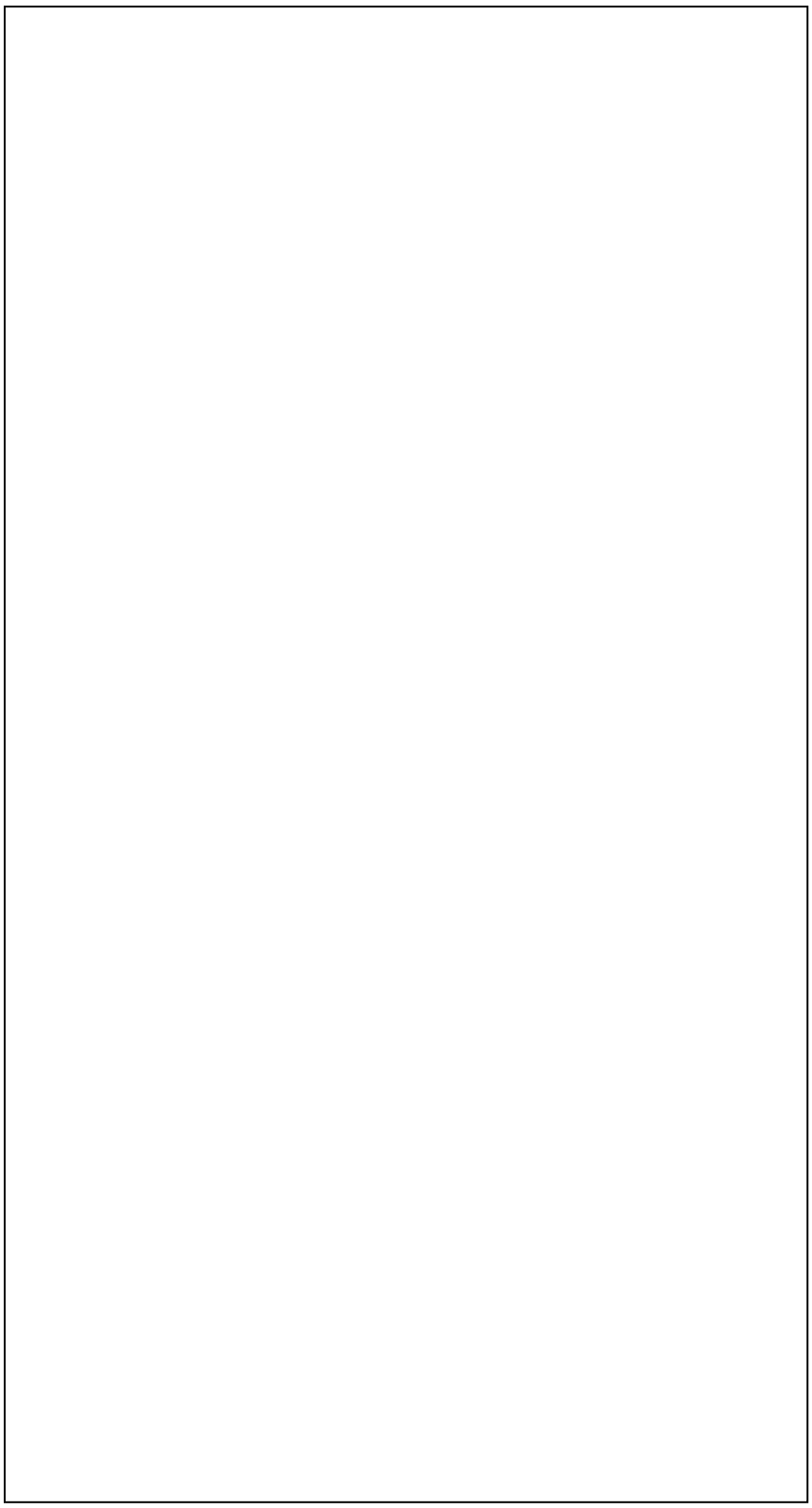

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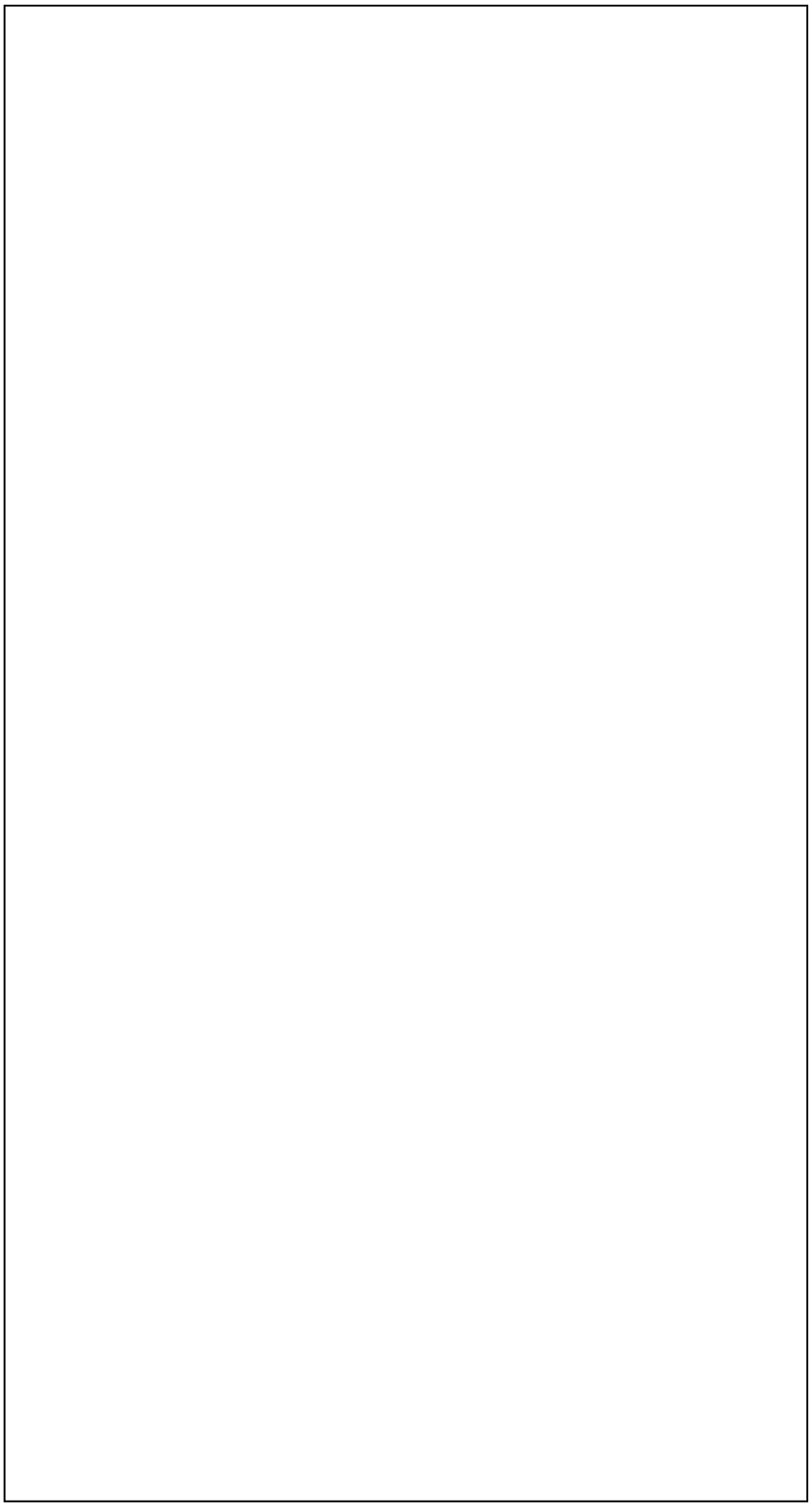


As mentioned earlier, Empire is still offering its current portfolio of demand-side programs to its eligible Missouri retail electric customers. Customer programs have been offered in Missouri since mid-2006. Empire provides updates on the existing programs to its Missouri Electric DSM Stakeholder Advisory Group on a quarterly basis. Due to an inadequate cost recovery mechanism, Empire has requested permission to terminate the existing demand-side programs in Case No. ER-2014-0351.

Load and Capability Balance Report Update

The Load and Capability Balance Reports for the 2013 IRP, the 2014 annual update and the 2015 annual update based on the five-year business plan (as of March 2015) are presented on the following pages for comparison. The 2015 annual update section contains updated forecasted peaks, updated projected coincident peaks of future DSM and updated ratings for a few of the existing units.

Forecast of Capacity Balance (MW)

Name of Utility: The Empire District Electric Company
Year of Electric Utility Resource Planning Filing: 2015 IRP Annual Update (Mar-2015)

	2013 IRP (July, 2013)					2014 IRP Annual Update (March, 2014)				
A. System Generation Capacity	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Base Capacity	** HIGHLY CONFIDENTIAL IN ITS ENTIRETY **					** HIGHLY CONFIDENTIAL IN ITS ENTIRETY **				
Asbury (coal)										
Iatan 1 (coal)										
Iatan 2 (coal)										
Plum Point (coal ownership portion)										
Ozark Beach (hydro)										
Total Base Capacity										
Intermediate Capacity										
State Line Combined Cycle (nat gas)										
Riverton Combined Cycle (nat gas)										
Total Intermediate Capacity										
Peaking Capacity										
Riverton 7 (nat gas)										
Riverton 8 (nat gas)										
Riverton 9 (nat gas)										
Riverton 10 (nat gas)										
Riverton 11 (nat gas)										
Riverton 12 (nat gas)										
Energy Center 1 (nat gas)										
Energy Center 2 (nat gas)										
Energy Center 3 (nat gas)										
Energy Center 4 (nat gas)										
State Line 1 (nat gas)										
Total Peaking Capacity										
Intermittent Capacity [1]										
Elk River (wind PPA)										
Meridian Way (wind PPA)										
Total Intermittent Capacity										
Percent Accredited Intermittent Capacity										
Total Accredited Intermittent Capacity										
Total Generation Capacity										
B. Capacity Transactions										
Purchases										
Plum Point (coal PPA)										
Total Purchases										
Sales										
Total Sales										
Net Transactions										
Total System Capacity										
C. System Peaks & Reserves										
Peak Demands										
Forecasted Peak (Managed Peak)										
less Future DSM										
Peak Demands less DSM										
Capacity Reserves										
D. Capacity Needs										
% Reserve Margin										
% Capacity Margin										
Required Capacity										
Capacity Balance										

[1] The wind resources are purchased power agreements (PPA).

Forecast of Capacity Balance (MW)

Name of Utility: The Empire District Electric Company
Year of Electric Utility Resource Planning Filing: 2015 IRP Annual Update (Mar-2015)

	2015 IRP Annual Update (March, 2015)				
A. System Generation Capacity	2015	2016	2017	2018	2019
Base Capacity	** HIGHLY CONFIDENTIAL IN ITS ENTIRETY **				
Asbury (coal)					
Iatan 1 (coal)					
Iatan 2 (coal)					
Plum Point (coal ownership portion)					
Ozark Beach (hydro)					
Total Base Capacity					
Intermediate Capacity					
State Line Combined Cycle (nat gas)					
Riverton Combined Cycle (nat gas)					
Total Intermediate Capacity					
Peaking Capacity					
Riverton 7 (nat gas)					
Riverton 8 (nat gas)					
Riverton 9 (nat gas)					
Riverton 10 (nat gas)					
Riverton 11 (nat gas)					
Riverton 12 (nat gas)					
Energy Center 1 (nat gas)					
Energy Center 2 (nat gas)					
Energy Center 3 (nat gas)					
Energy Center 4 (nat gas)					
State Line 1 (nat gas)					
Total Peaking Capacity					
Intermittent Capacity [1]					
Elk River (wind PPA)					
Meridian Way (wind PPA)					
Total Intermittent Capacity					
Percent Accredited Intermittent Capacity					
Total Accredited Intermittent Capacity					
Total Generation Capacity					
B. Capacity Transactions					
Purchases					
Plum Point (coal PPA)					
Total Purchases					
Sales					
Total Sales					
Net Transactions					
Total System Capacity					
C. System Peaks & Reserves					
Peak Demands					
Forecasted Peak (Managed Peak)					
less Future DSM					
Peak Demands less DSM					
Capacity Reserves					
D. Capacity Needs					
% Reserve Margin					
% Capacity Margin					
Required Capacity					
Capacity Balance					

[1] The wind resources are purchased power agreements (PPA).

7. 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 five special contemporary issues (a through e) that were established by Commission Order in File No. EO-2015-0042.

a. Review the impact of foreseeable emerging energy efficiency technologies throughout the 20-year planning period;

In the 2014 annual update, Empire addressed a similarly-worded Special Contemporary Issue. In the time since, a few details about emerging efficiency technologies have become clearer. Empire—as well as its consultants—continues to monitor and observe trends in emerging energy efficiency technologies as a practice. Empire's response to this Special Contemporary Issue is very similar to the 2014 annual update response, with small changes to reflect its observations. Empire will continue to observe and analyze emerging energy efficiency technologies as part of its 2016 triennial compliance filing.

The impacts of foreseeable emerging energy efficiency technologies are inherently difficult to predict for two reasons:

1. Foreseeable emerging technologies, i.e., technologies which are at least known at the time of the planning effort, do not necessarily enter the market in a predictable manner. Uptake of new technologies is subject to the same economic factors that affect established technologies including interactions between avoided costs, and incremental costs. However, new technologies often experience unpredictable barriers due to performance, reliability, consumer and market acceptance, and other factors that do not affect established technologies.

2. Public policy plays an important role in driving technology development, and in some cases (such as lighting) is the primary driver. Policy factors such as new or modified legislation or regulations at the state or federal levels have significant impacts of the introduction of new technologies and how they are treated in an analysis.

In the 2013 IRP, Empire addressed changes in technology by incorporating trends in impacts and incremental costs over the planning period to assess when specific measures would be cost-effective, and could be incorporated into the portfolio. Empire proposes to take a similar approach in future IRP cycles. First, the portfolio design accounted for changes in equipment standards, both federal minimum efficiency standards and Energy Star Consortium for Energy Efficiency (ENERGY STAR/CEE) efficiency requirements. Second, incremental costs were reduced for certain technologies to reflect expected changes in costs and pricing as technologies mature and market penetration increases. For example, costs associated with advancements in metering and distribution technologies, such as two-way communicating meters and programmable thermostats, were estimated to decrease as were costs associated with solar and wind renewable technologies. As the costs associated with these energy efficiency technologies decreased, they became cost-effective at various times during the planning horizon, depending on the avoided costs.
At this point, several technologies and measures may warrant this kind of analysis in the future.

- Residential general purpose LED lighting: Rapid changes in pricing are occurring in the market with increased adoption of LED lighting, especially in specialty applications. This is expected to continue into the general purpose lighting market, although this is a more competitive market with alternatives such as CFLs and halogens.

- Residential consumer electronics: Consumer electronics continue to evolve and become more capable, and also account for larger shares of electricity consumption in the residential sector. Consumers quickly adopt and abandon technologies primarily based on performance rather than energy efficiency. Nevertheless, these technologies may account for additional efficiency opportunities.

- Commercial general purpose LED and T5 fluorescent lighting: The de facto baseline for most general purpose commercial lighting is now the T-8 linear fluorescent lamp. As in the residential sector, alternatives are available, including LED tubes, LED arrays, and T-5s, and costs and performance are changing quickly.

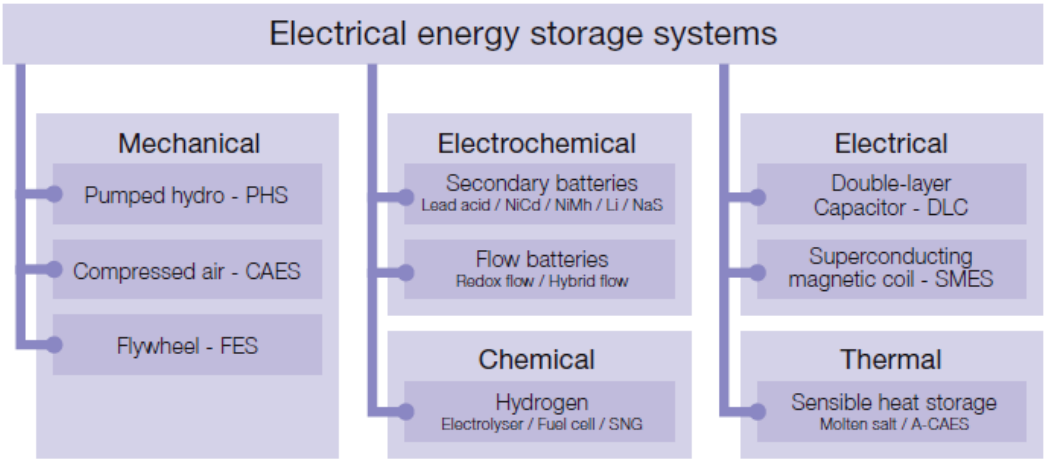
- Advanced building controls: Building control systems have typically been restricted to larger applications due to cost and complexity. However, a new range of wireless monitoring and control equipment, along with user-friendly web-based interfaces, is making it possible to reduce "wasted energy" by optimizing end use operations at a smaller scale.

- Advanced metering and communications: Advances continue to take place in advanced metering equipment and communications. In addition, there is

considerable potential overlap in building controls and metering/communications technologies.

b. Review the impact of foreseeable emerging energy storage technologies throughout the 20-year planning period;

Emerging storage technologies may play roles on either the supply or demand side. Regardless of type, storage technologies are "dispatchable" resources that may be used to manage customer or utility load profiles, provide critical back-up power, or provide storage for intermittent renewable resources. There are two major emerging market needs for electrical energy storage as a key technology: to utilize more renewable energy and less fossil fuel, and the future Smart Grid. Large scale, stationary applications of storage technologies are limited by the high costs of the available technologies. In the near term, stationary applications on the utility system or at customer sites are expected to be limited to conventional battery storage for back-up and emergency power where the loss of power would result in very high security or safety risk, or very high economic losses. Such applications may include data centers and emergency operations facilities. Even in these cases, storage is used only for short time periods until emergency generators are available.



A Classification of Electrical Energy Storage Systems

The most important factor for the broader application of storage technologies is cost, and much of the development of storage technologies, including cost reductions, is currently focused on batteries for electric vehicles. A potentially important interaction between utilities and customer-owned storage may actually emerge in the transportation sector as electric vehicles develop. So called "vehicle-to-grid" technologies are currently under development and being tested to understand how electric vehicles may provide accessible storage for utility operations (spinning reserve, renewable energy storage, etc.). However, the introduction of this technology is highly unpredictable due to the effects of oil prices on consumer demand for electric vehicles, and consumer acceptance of the

technology. It is also possible that the many advances being made for energy storage in the automotive industry could eventually be leveraged to result in whole-home-scale and possibly even larger- and/or utility-scale technologies. If this assessment is correct, just as the progress of EV-related storage is tied to the volatility of oil prices and the trajectory of the automotive industry, so are future innovations in larger-scale energy storage.

c. Analyze and document the future capital and operating costs faced by each Empire coal-fired generating unit in order to comply with the following environmental standards

(1) Clean Air Act New Source Review provisions;
(2) 1-hour Sulfur Dioxide National Ambient Air Quality Standard;
(3) National Ambient Air Quality Standards for ozone and fine particulate matter;
(4) Cross-State Air Pollution Rule, in the event that the rule is reinstated;
(5) Clean Air Interstate Rule;
(6) Mercury and Air Toxics Standards;
(7) Clean Water Act Section 316(b) Cooling Water Intake Standards;
(8) Clean Water Act Steam Electric Effluent Limitation Guidelines;
(9) Coal Combustion Waste rules;
(10) Clean Air Act Section 111(d) Greenhouse Gas standards for existing sources; and
(11) Clean Air Act Regional Haze requirements.

This is a repeat issue from the 2014 annual update. For that update Empire sought clarification regarding this issue. The issue requires Empire to analyze and document the future capital and operating costs faced by each Empire coal-fired generating unit to comply with eleven different environmental standards. Empire asked whether the Commission is requiring it to document the cost to comply with each of the eleven environmental standards separately. Empire explained that all of its air quality control projects are designed to satisfy multiple environmental standards at once. The Commission clarified as follows: "The Commission is interested in the cost associated with compliance by each coal-fired generating unit with the eleven environmental standards in total. Empire does not need to separately breakdown the cost to comply with each of the eleven environmental standards." Based on that guidance, Empire has updated its response from last year as follows:

[1] Denotes an engineering estimate in the following response.

In December 2014 Empire completed an environmental retrofit at the Asbury plant. The retrofit project included the installation of a pulse-jet fabric filter (baghouse), circulating dry scrubber and powder activated carbon injection system. This new equipment enables Empire to comply with the Mercury and Air Toxics Standard (MATS). Construction costs through December 31, 2014 were $110.9 million for the project to date, excluding AFUDC. Final cost is expected to range from $112.0 million to $130.0 million, excluding AFUDC.

Empire has and will continue to incur capital and operating costs at its coal-fired generating facilities to comply with existing and future environmental regulations. At Asbury, for instance, with the AQCS project operating costs are expected to be approximately **_____** annually in addition to the approximately $1.1 million that will be spent annually to operate and maintain the selective catalytic reduction (SCR) system previously installed. Asbury is also constructing a landfill for its ash and scrubber byproduct at a cost of approximately **_____**. The eventual closure of this landfill is expected to be around **_____**, while operating costs are expected to be **_____** (in addition to the **_____** included for ash and byproduct handling included in the Asbury AQCS operating costs above) during active operation and **_____** per year post-closure. In addition, Asbury has budgeted approximately **_____** for future conversion to a dry bottom ash conveyance system.

Riverton Units 7 and 8 (formerly coal units) were transitioned to natural gas only operation in September 2012 prior to their eventual retirements. Riverton Unit 7 was retired from service in June 2014, and Units 8 and 9 are scheduled to retire upon the completion of the Riverton Unit 12 combined cycle conversion in mid-2016. Although the Riverton Unit 12 combined cycle conversion is a natural gas-fired project, it is included in this discussion because it is being undertaken to replace coal-fired capacity whose retirements were accelerated due to environmental regulations. The conversion of the existing unit 12 to a combined cycle operation is expected to cost $165-$175 million (without AFUDC), which includes approximately **_____** for construction of a cooling tower and 316(b)-compliant river water intake. Operating costs for the SCR on the combined cycle unit are expected to be approximately $60,000 annually. Costs associated with the retirement of Riverton Units 7, 8 and 9 include approximately $1.43 million that was spent to close the existing ash landfill and approximately **_____**for the environmental remediation and demolition of the units. Operating costs for the landfill post-closure are forecast to be approximately **_____** per year. On Empire's 7.52% ownership share of Plum Point, annual costs for operating the air pollution control equipment and the fly ash landfill were approximately $445,000 in

2014. There is also the infrequent need to construct a new landfill cell – the last cell constructed cost approximately $290,000.

On Empire's 12% ownership share of the two units at the Iatan Station, annual operating costs for the air quality control system and ash landfill were approximately $760,000 in 2014. There will also be the need to construct additional landfill cells in the future at a frequency and a cost that is yet to be determined.

d. Analyze and document the cost of any transmission grid upgrades or additions needed to address transmission grid reliability, stability, or voltage support impacts that could result from the retirement of any existing Empire coal-fired generating unit in the time period established in the IRP process.

Empire addressed a similarly-worded Special Contemporary Issue in the 2014 annual update. After reviewing last year's response, there were only minor changes. The updated response is provided below:

As discussed in issue c above, Riverton Unit 7 (38 MW) was retired in June 2014 and Riverton Units 8 and 9 (54 MW and 12 MW respectively) are slated to retire in mid-2016 due to MATS and unit age. Due to the retirement of the aforementioned 104 MWs, the effects on the 69kV system have initiated Riverton Unit 12 Combined Cycle installation to replace the loss of capacity. The expansion of Substation #453 and an upgrade to the Riverton auto transformer are needed to bring the new capacity online. The costs associated with the upgrades are estimated to be approximately $5.395 million. Asbury Unit 2 retired on December 31, 2013. The impact to the 161kV system does not have an adverse effect on Empire's transmission system(s). No upgrades were identified related to the retirement of Asbury Unit 2.

e. Analyze and document the range of potential levels of distributed generation in Empire's service territory for the 20-year planning horizon and the potential impacts of each identified level of distributed generation, and in particular distributed solar generation, on Empire's preferred resource plan. The potential impacts should quantify both the amount of electrical energy the distributed generation is expected to provide to the grid and the amount of electrical energy that the distributed generation customers are expected to consume on site that will offset the amount that the company would normally provide to those customers.

Distributed generation (DG), also known as on-site generation, distributed resources, distributed energy resources or dispersed power, is the use of small-scale power generation technologies located close to the load being served. DG is currently being used by some customers in the United States and worldwide to provide some or all of their electricity needs. Examples of DG resources include reciprocating engines, microturbines, small combustion gas turbines, fuel cells, photovoltaic (PV) solar and small wind turbines.

DG was considered in Empire's 2013 IRP, both in the supply-side and demand-side analysis. The 2013 IRP considered 18 alternate plans, and DG does appear in the outer years of some of the plans, probably due in part, to the capacity expansion optimization model algorithms utilizing DG's small size to help converge to a solution. Utility scale solar (in 10 MW net increments) was considered in the supply-side analysis and residential solar PV was considered as a potential program in the DSM analysis. In the demand-side resource analysis residential solar was screened out as not being cost effective in most of the 18 alternate plans, but it was utilized in the outer years of the most aggressive DSM portfolios. However, solar prices have been declining and will need to be updated in future studies.

As mentioned earlier in this report, Empire has had an exemption from the 2% solar requirement of the Missouri renewable energy standard. On February 10, 2015 the Missouri Supreme Court overruled the solar rebate exemption that was extended to Empire in 2008. At this time, Empire has asked for reconsideration. It is Empire's understanding that this process could take several months. This will impact the 2016 IRP's 20-year study period; but it is not expected to have a significant cost impact on the current preferred plan. Empire will reconsider DG, including supply-side and demand-side solar, with updated planning assumptions in its next IRP filing.

At this time Empire has 41 net-metered solar PV customers. Thirty-seven of these customers are located in Missouri. Overall, 35 are residential installations, five are commercial and one is industrial. The total installed capacity is about 259.6 kW with an annual estimated energy of about 341,114 kWh, representing about 0.008% of Missouri retail sales.

The following table illustrates the current Missouri RES. It is based on a percentage of a utility's Missouri retail sales. The 2% required solar portion, if applied to Empire's Missouri retail sales, would be a 0.1% annual requirement from 2015-2017; a 0.2% annual requirement from 2018-2020; and a 0.3% annual requirement from 2021 onward. In terms of MWh of energy, this would be roughly 4,100 annual MWh from 2015-2017;

about 8,300 annual MWh from 2018-2020; and approximately 12,600 annual MWh from 2021 onward adjusted for future growth.

Missouri Renewable Energy Standard

Dates	RES Energy (no less than)
2011-2013	2%
2014-2017	5%
2018-2020	10%
Beginning in 2021	15%

2 percent of the energy requirement from solar

The outlook for solar in the United States holds both promise and uncertainty. There is substantial promise for future technology gains and cost reductions. On the other hand, no one knows for sure whether these improvements will surpass or fall short of what the industry hopes will be achieved. Finally, there is political uncertainty. It is anticipated that the solar industry will need at least indirect support in the form of climate programs, tax credits, grid integration, and transmission improvement if it is to realize its full potential.