RECLASSIFIED NON-PROPRIETARY

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

Volume I
Executive Summary, Introduction

September 2010

Reclassified May 20, 2011

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ES.0 Executive Summary

ES.1 Overview

The Empire District Electric Company (Empire) has conducted its analysis of future loads and resources for this Integrated Resource Plan (IRP) to comply with the requirements of 4 CSR 240-22 (Rule or IRP Rule) based on Empire's interpretations of the Rule. Empire requested variances and clarifications from the Missouri Public Service Commission (MPSC) for those instances in which this IRP is at variance with the Rule. The MPSC issued an order granting Empire's application for variance in June 2010 (EE-2010-0246).

This periodic IRP analysis, in conjunction with Empire's normal planning process, assists Empire in making decisions concerning the timing and type of system expansion that should ultimately occur. The results of the IRP analysis documented in this report reflect only current and projected conditions as they were known at the time that the results were developed. Empire will re-examine its capacity expansion decisions as the need for additional resources, driven by load growth, and the influence of external factors, primarily environmental, become more evident. Specifically, the need for completion of additional supply-side capacity and environmental upgrades around the 2015 timeframe will be reexamined periodically before a firm decision is made as to the timing and type of resource that might be added. The preferred plan, implementation plan, and resource acquisition plan (Plans) presented in this IRP have been approved by a committee of Empire's senior management[1] at the time of this IRP filing (September 2010). Figure ES-1 shows the highlights from the early years of the Preferred Plan.

The Plans will be subjected to ongoing evaluation as modeling assumptions change based on evolving business conditions and as environmental laws and regulations become more codified.

[1] The senior management team that approved this IRP consists of Brad Beecher, Executive Vice President and COO – Electric; Greg Knapp, Vice President – Finance and CFO, Kelly Walters, Vice President – Regulatory and General Services; and Harold Colgin, Vice President – Energy Supply. The entire IRP team is listed in Appendix A.

Figure ES-1
Preferred Plan Highlights for the Early Years of the IRP

- **Proposed Changes to Existing Resources**
    - Air Quality Control System (AQCS) installed on the Asbury coal-fired unit in the 2015 timeframe
    - Asbury unit 2 retires when the Asbury AQCS project is completed
    - Riverton coal-fired units 7 and 8 converted to natural gas in the 2015 timeframe before their potential retirement in the 2018 timeframe
    - The depreciation treatment for both Asbury and Riverton units 7 and 8
    - Riverton unit 12 combustion turbine incorporated into a new combined cycle unit in the 2015 timeframe
    - Continuation of the existing demand-side resource portfolio
- **Proposed New Supply-Side Resources**
    - Plum Point coal-fired unit begins operation in 2010
    - Iatan 2 coal-fired unit expected to begin operation in 2010
    - Riverton unit 12 combined cycle conversion in the 2015 timeframe
- **Proposed New Demand-Side Management**
    - Home Energy Comparison Reports implemented in 2010 timeframe
    - Low Income Assistance Program continued in 2011
    - ENERGY STAR® Appliance Rebates – Washing Machines implemented in 2011
    - Residential High Efficiency Lighting implemented in 2011
    - Residential High Efficiency Cooling (referred to as Central Air Conditioning (CAC)) implemented in 2015
    - Residential Direct Load Control implemented in 2015
    - Large Commercial and Industrial (C&I) Voluntary Interruptible/Peak Load Reduction Program implemented in 2015

ES.2 Implementation Plan

During 2010, the construction of the Plum Point coal-fired generating unit has been completed and the unit met its in-service criteria on August 12, 2010. Empire has a 7.52% (approximately 50 MW) undivided ownership share of the unit plus a 50 MW power purchase agreement (PPA). Iatan 2 is anticipated to enter commercial operation during the fall of 2010. Kansas City Power & Light is the majority owner-operator of the coal-fired Iatan 2 unit; Empire's share of the unit is 12% (approximately 102 MW).

The demand-side management (DSM) programs that have been implemented include:

- Low Income Weatherization
- Low Income – New Homes
- Home Performance with ENERGY STAR®
- Residential High Efficiency Lighting (ENERGY STAR® Change a Light)
- Residential High Efficiency Central Air Conditioning (CAC)
- ENERGY STAR® Homes

- Commercial and Industrial (C&I) Rebate
- Building Operator Certification Program
- Interruptible Service Rider

Evaluation, Measurement & Verification (EM&V) studies for several of these programs have been completed since the 2007 IRP was filed or are currently in process.

As a result of its current resource commitments in conjunction with the analysis results from this IRP, Empire will:

- Evaluate the adequacy of water and the availability of associated water rights at the Riverton station to determine if such could support the conversion of Riverton Unit 12 to a combined cycle unit either with Riverton 7 and 8 retired or with Riverton 7 and 8 in continued operation. Examine the trade-offs associated with the continued operation of Riverton 7 and 8 that might be necessary for water and air permits to accomplish the Riverton 12 conversion.
- Monitor the Riverton 7 and 8 coal-fired units for environmental compliance to determine at what point the units should be retired or converted to natural gas operation, if needed, prior to their retirement.
- Begin discussions with the parties to Empire's IRP on the regulatory treatment of the terminal removal costs and depreciation reserve associated with the retirement of Riverton 7 and 8.
- Monitor carbon dioxide (CO_2) best available control technology (BACT) permitting requirements in the States of Kansas and Missouri and at the Federal level as they relate to permitting the conversion of the Riverton 12 combustion turbine to a combined cycle unit and potential permitting requirements for the Asbury AQCS.
- Complete analysis regarding the feasibility of installing a scrubber, baghouse and powder activated carbon system at Asbury 1 (referred to as the Asbury AQCS). Associated with the Asbury AQCS and other pending environmental regulations are decisions relating to the need for an ash landfill and bottom ash conveyance equipment at the Asbury unit.
- Begin discussions with the parties to Empire's IRP on a depreciation rate for the remaining life at Asbury before Empire begins the process to construct the AQCS and associated equipment at Asbury or the treatment of the terminal removal costs and depreciation reserve associated with the retirement of the Asbury plant.
- Work with the parties to the IRP prior to Empire moving forward with AQCS additions expeditiously, potentially before the Clean Air Transport Rule (CATR) and mercury/Hazardous Air Pollutants (Hg/HAPS) rulemakings are finalized in order to limit equipment, engineering, and contractor availability risks.
- Initiate discussion with the parties to Empire's IRP on the regulatory approach to Empire moving forward with the dry ash landfill and dry conveyance potentially before the ash rulemaking (Coal Combustion Residuals (CCR)) is finalized.
- Issue a Request for Proposals for the Asbury AQCS project.
- Issue an RFP for the 2015 timeframe resource.

- Track and evaluate results of the implementation of DSM programs and keep the Customer Programs Collaborative (CPC) informed as to the results.[2]
- Monitor federal efforts regarding carbon regulations.

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".

Table ES-1 outlines the steps that Empire might take to implement the DSM programs selected in the Preferred Plan, to install the AQCS at Asbury by 2015, to convert Riverton 7 and 8 to natural gas only as of 2015, and to start the process for procuring a supply-side resource in the 2015 timeframe.

[2] The Customer Programs Collaborative was established as a result of a stipulation and agreement and, in addition to Empire personnel, is comprised of Missouri Public Service Commission (MPSC) staff, Office of Public Counsel, Missouri Department of Natural Resources, and other interested parties. The CPC is charged with making decisions pertaining to the development, implementation, monitoring, and evaluation of Empire's affordability, energy efficiency, and demand response programs.

Table ES-1
Implementation Plan Timeline

Timeframe	Action
October 2010	Capital budget reflecting Year 1 of Preferred Plan prepared
October-December 2010	Begin development of ash landfill, if required[1]
	Begin development of 2015 timeframe resource, as appropriate[2]
2010, 2011	Periodic meetings of the CPC to oversee implementation, progress and evaluation of DSM programs
1st Quarter 2011	Begin development of Asbury AQCS RFP
	Begin development of 2015 timeframe resource RFP[2]
April – October 2011	Decision to move forward with 2015 timeframe resource, as appropriate[2]
October 2011	2012 capital budget reflecting Preferred Plan 2015 timeframe resource[2]
2012-2015	Periodic meetings of the CPC to oversee implementation, progress and evaluation of DSM programs
2015 timeframe	Conversion/retirement of Riverton coal-fired units due to anticipated environmental regulations/laws, as appropriate
	Completion of Asbury AQCS, as appropriate

1. The EPA has already delayed the comment period on ash regulations for an additional 60 days to November 20, 2010.
2. As Empire changes its forecast, the need to develop and issue an RFP for resources and other items in this timeline will change as well

Empire will continue to monitor federal legislative and regulatory requirements associated with renewable portfolio standards (RPS) in addition to tracking changes in other environmental regulations. With its current purchases of wind energy from both the Elk River and Meridian Way Wind Farms, Empire meets the percentages of renewable energy now required by the States of Missouri and Kansas for the near-term time period covered in the implementation plan.

ES.3 High Level Resource Acquisition Strategy

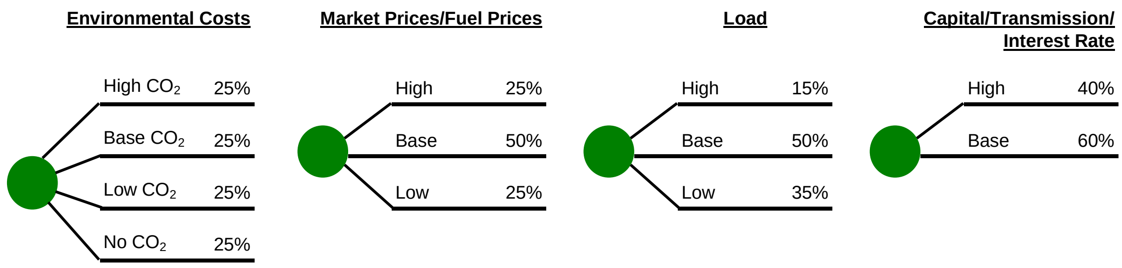
The Empire Resource Acquisition Strategy (RAS), required as part of the filing of this IRP, was formally approved by a committee of senior management at a meeting on August 30, 2010.[3] The Preferred Plan incorporated in this IRP is documented in Section ES.11 of this Volume and further discussed in Volume V of this IRP. The Implementation Plan is documented above in Section ES.2 of this Volume and further discussed in Volume V of this IRP.

The critical uncertain factors Empire has identified include environmental costs, market prices/fuel prices, load, and capital/transmission/interest costs (See Figure ES-2). As part

[3] The senior management team composition was previously documented in this Volume. A listing of the entire IRP team is shown in Appendix A.

of the normal course of business, these factors are monitored very closely by Empire personnel in coordination with senior management.

Figure ES-2
Critical Uncertain Factors



Company personnel monitor environmental regulations and requirements to determine what actions need to be undertaken to ensure compliance and to determine the costs associated with that compliance. Among the environmental issues Empire is currently tracking are issues relating to ozone; sulfur dioxide (SO_2); nitrogen dioxide (NO_2); the Clean Air Interstate Rule (CAIR) and its impending replacement rule, the Clean Air Transport Rule (CATR); water; particulate matter, specifically for 2.5 micrometers ($PM_{2.5}$); the Coal Combustion Residuals (CCR) rule relating to ash; mercury and hazardous air pollutants (Hg/HAPS); and carbon dioxide (CO_2). The information gathered is shared through discussions with senior management.

Power prices and fuel prices are regularly monitored by operational personnel. Both operational personnel and senior management are kept abreast of the processes and procedures being implemented in the Southwest Power Pool (SPP) that directly impacts the availability and pricing of power. The price of natural gas is closely monitored. As documented in Volume III, Empire implemented a natural gas risk management policy that has an objective of minimizing the impact of natural gas price volatility. The risk management policy includes monitoring of natural gas prices. The natural gas risk management policy is overseen and positions taken are approved annually by senior management.

Empire's load forecast is revised annually and close attention is paid to the levels of peak demand during the summer and winter months. Scheduled reviews on the load forecast are held with senior management. Each month, Empire prepares a variance report related to the demand and energy forecast and the actual results.

The capital costs associated with generation and transmission projects are monitored by Empire in a variety of ways. A project development team is formed for each major generation project with direct line reporting to a member of senior management. Finance personnel monitor the markets daily to track interest rates, are in frequent contact with the rating agencies, and are kept abreast of planned budgets for new projects. These efforts are coordinated with members of senior management.

Empire's operating structure is organized in such a manner that senior management is both involved in and well-informed as to the key factors that have been identified in this IRP as the critical uncertain factors. Due to the level of communication and information flow within the Company, significant changes in these factors can be addressed immediately with appropriate changes to the Preferred Plan, implementation plan, or any other portion of the IRP prior to the next scheduled IRP filing (2013).

Empire will determine the range of outcomes within which the Preferred Plan is judged to be appropriate in accordance with 4 CSR 240-22.070. One such item related to the environmental critical uncertain factor is the regulatory treatment of costs and depreciation associated with both the Asbury AQCS project and the potential retirement of Riverton 7 and 8. An item that is related to the capital uncertain factor is the construction cost associated with the Asbury AQCS project which will be determined after the receipt of responses to the Asbury AQCS RFP. As previously mentioned, the load critical uncertain factor could influence the timing for new supply-side resources and DSM programs. Through its monitoring of the critical uncertain factors, Empire may decide that changes to its Preferred Plan are warranted.

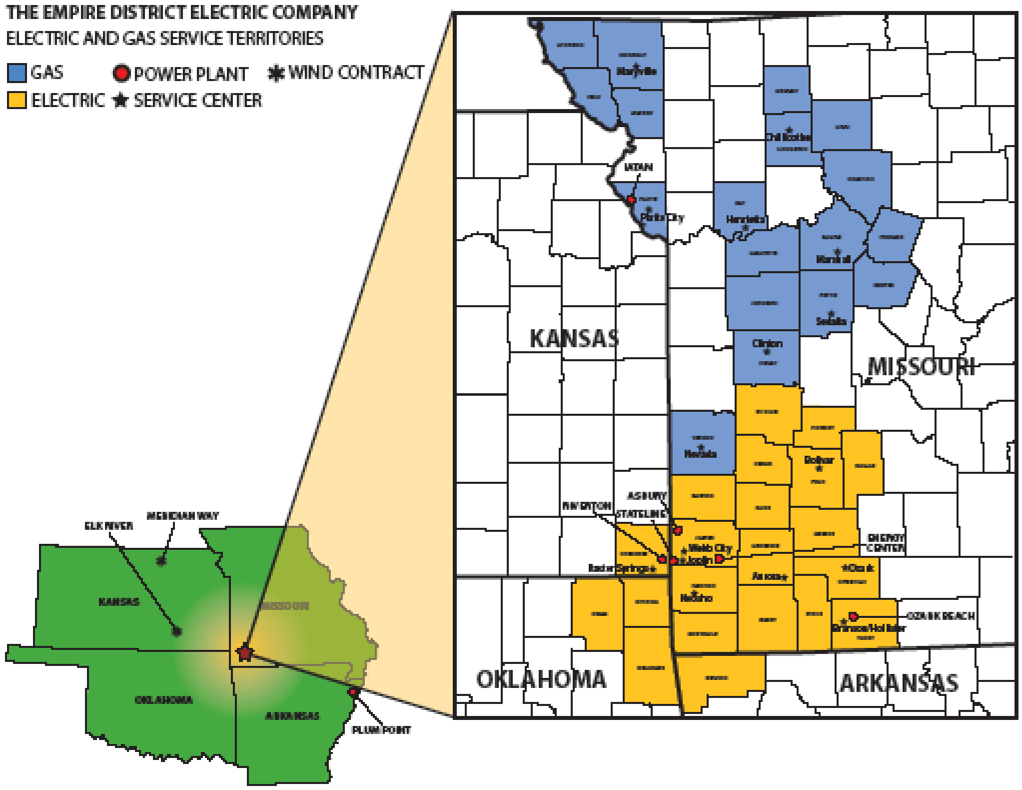
ES.4 Company Situation

Empire is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire's service territory includes an area of about 10,000 square miles with a population of over 450,000. The service territory is located principally in southwestern Missouri and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas (see Figure ES-3 and Table ES-2). The principal activities of these areas include light industry, agriculture and tourism.

Table ES-2
Counties in Empire's Service Territory (Electric)

State	Counties (Alphabetical Order)
Missouri	Barry, Barton, Cedar, Christian, Dade, Dallas, Greene, Hickory, Jasper, Lawrence, McDonald, Newton, Polk, St. Clair, Stone, Taney
Kansas	Cherokee
Oklahoma	Craig, Delaware, Ottawa
Arkansas	Benton

Figure ES-3
Empire District Electric Service Territory



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

Empire also provides natural gas (through its wholly-owned subsidiary, The Empire District Gas Company), water service, and fiber optics.

ES.5 Integrated Resource Planning

Integrated resource planning for electric utilities has evolved considerably over the past twenty years and can no longer solely be used to identify the least cost resources; such a plan must explicitly consider risks and uncertainties. Empire's objectives in preparing the 2010 IRP reflect its commitment to provide cost-effective, safe, and reliable electric service to its customers and include:

- to provide reliable electricity service while complying with all environmental requirements
- to minimize the cost of providing electric service
- to achieve and/or maintain investment grade ratings on its debt to provide corporate financial stability and minimize financing costs
- to accommodate and manage a broad range of industry uncertainties.

ES.6 Situational Analysis

The IRP process has evolved in order to meet the increasing uncertainty in the industry. The increase in uncertainty is primarily related to economic conditions, increased environmental regulation, and federal and state regulatory trends. The financing of power plants has been a difficult task for many years. The uncertainty associated with carbon regulation/legislation has only increased this difficulty. The recent focus in generation expansion for the industry has turned toward the development of renewable energy resources and the installation of environmental retrofits on existing coal-fired units.

Against this financial backdrop, electric utilities are still required to forecast customers' peak demand and energy requirements over a long-term planning horizon, implement cost effective demand-side management (DSM) programs, procure the resources to meet customer's needs and the utility's legal obligation to serve customers, and comply with state regulatory mandates including those in the area of integrated resource planning. Empire recently experienced a decrease in peak demand (2008 and 2009) and Empire's summer peak of 2010 was lower than the summer peak of 2007. Obviously, some of this activity is related to weather, but some of this decline is also attributable to the recent economic downturn. For example, extreme winter weather in 2010 led to the Company's establishment of an all-time peak demand in January 2010. The period of time it will take to return to "normal" or the development of a "new normal" is still unknown. Environmental regulations, in addition to potential carbon legislation/regulation, continue to dictate the operation, maintenance, and potential retirements of and upgrading of existing generation units.

All of these factors require a utility's plans to be as flexible as possible in order to deal with the constantly changing business environment. Empire is striving to maintain its flexibility, to keep an eye on the many factors that constantly change in its business, and to develop an IRP that will reliably meet the needs of its customers in the most economic manner using the best information it has at the time of the IRP filing.

ES.7 Assumptions

A wide variety of assumptions must be used to develop an IRP. In addition to the load forecast, assumptions must be developed for fuel price forecasts, market price forecasts, planning margins, financial parameters, emission costs, and parameters specific to resources including size, capital costs, heat rates, forced outage rates, maintenance schedules, and operating and maintenance costs. The base case assumptions used in Empire's IRP reflect the enactment of a CO_2 cap and trade system (referred to in this IRP as a carbon tax or carbon costs) with an effective date of 2015. Within the plans evaluated as part of the IRP, four levels of CO_2 regulation were examined including a plan in which no CO_2 tax is enacted throughout the planning horizon.

ES.8 Load Forecast

Empire produced class level forecasts by season using regression analysis at the customer class level for purposes of this IRP. Customer, weather, energy usage, and trend variables were utilized when applicable. Additionally, a system level peak and energy (NSI) forecast was developed to check and support the multiple rate class forecasts. The load impacts of implemented DSM programs have been incorporated in the base load forecast. Empire requested variances and clarifications from the MPSC for various areas of the load forecasting process that are at variance with 4 CSR 240-22. The MPSC issued an order granting Empire's application for variance in June 2010 (EE-2010-0246).

ES.9 Demand-Side Management

The DSM resource options included in the IRP for the entire Empire system reflected the following programs that passed initial screening:

- **Residential**
  - Low-Income Assistance Program
  - Residential High Efficiency Lighting
  - Residential High Efficiency Cooling Program
  - Refrigerator Pickup Program
  - Home Performance with ENERGY STAR®
  - Home Energy Comparison Reports
  - ENERGY STAR® Appliance Rebates
    - Refrigerators
    - Washing Machines
    - Dehumidifier
  - Direct Load Control
- **Commercial and Industrial (C&I)**
  - Commercial Prescriptive Rebate Program
  - Commercial Custom Rebate Program
  - Large C&I Turnkey Energy Efficiency Program
  - Small Business Direct Install
  - Business Owner Certification Program
  - Large C&I Voluntary Interruptible/Peak Load Reduction Program

Residential solar photovoltaics (PV) was one of the programs also considered in the DSM analysis, but it did not pass the initial economic screening.

ES.9.1 Missouri

The Customer Programs Collaborative (CPC), consisting of Empire, MPSC staff, Office of Public Counsel, Missouri Department of Natural Resources, and other interested parties, is charged with making decisions pertaining to the development, implementation, monitoring, and evaluation of Empire's affordability, energy efficiency, and demand response programs. Under the auspices of the CPC, a collection of DSM programs was identified as cost effective for implementation over a five-year horizon and implementation was begun. These programs included:

- Low Income Efficiency Program
- Low Income – New Home Program
- Home Performance with ENERGY STAR® Program
- Residential High Efficiency Lighting (ENERGY STAR® Change a Light)
- Residential High Efficiency Central Air Conditioning (CAC)
- ENERGY STAR® Homes
- Commercial and Industrial (C&I) Rebate
- Building Operator Certification Program
- C&I Peak Load Reduction
- Interruptible Service Rider

Efforts undertaken to date and planned efforts on this range of DSM programs are shown on Table ES-3.

Table ES-3
DSM Program Implementation – Missouri

Program	2006	2007	2008	2009	2010	2011	2012
Low Income Weatherization	x	x	Xe	x	x		
Change a Light	x	x	Xe	x	x		
Low Income New Homes		x	x	x	Xe	x	
Central AC		x	x	Xe	x	x	
C&I Rebate		x	x	Xe	x	x	
Building Operator Certification			x	x	Xe	x	x
Home Performance with ENERGY STAR®				x	x	Xe	x
ENERGY STAR® Homes				x	x	Xe	x
C&I Peak Load Reduction				x	x	x	x
Notes: x = program implemented. Xe – evaluation year based on portfolio plan.							

ES.9.2 Kansas

On January 29, 2010, Empire filed an Application with the Kansas Corporation Commission (KCC) for approval to implement its portfolio of energy efficiency and demand response programs for its Kansas customers. On June 3, 2010, a Joint Motion to

Approve the Stipulation and Agreement was filed with the KCC with a requested effective date of July 1, 2010. The motion was approved and all programs were implemented July 1, 2010 as pilot programs – with three-year lives.

Empire's DSM pilot programs in Kansas are designed to:

- offer programs across all customer classes and income levels
- follow current industry best practices and incorporate them in program design
- provide education to customers
- include sufficient budget
- demonstrate cost effectiveness

In the development of its DSM portfolio for its Kansas customers, Empire has striven to ensure compliance with KCC guidelines for EM&V. In compliance with KCC Order 422, each direct impact program has undergone benefit/cost screening consistent with the California Standard Practice Manual. All five perspectives – Total Resource Cost, Societal, Participant, Ratepayer Impact Measure (RIM), and Utility Cost – have been analyzed. Two benefit/cost analyses have been conducted for each program and for the portfolio as a whole.

The programs in the portfolio are:

- Low Income Efficiency Program
- Residential High Efficiency CAC Program
- C&I Rebate Program
- Building Operator Certification Program
- C&I Peak Load Reduction Program

ES.9.3 Oklahoma

Empire's slate of four DSM programs in Oklahoma is designed to help customers improve their energy efficiency, reduce their peak demand, and save money. This portfolio of programs resulted from an energy efficiency potential study undertaken for Empire's Oklahoma customers. Together, the programs provide incentives that cover the major end uses for all customer classes. In addition, the programs strike a balance between energy efficiency and demand response programs, and do not promote fuel switching. All of the programs in the Oklahoma portfolio have been successfully deployed by many other electric utilities throughout the U.S. The four programs are:

- Low Income Weatherization Program
- Air Conditioning Tune-Up and Replacement Program
- C&I Prescriptive Rebate Program
- C&I Interruptible Rider Program

ES.9.4 Arkansas

Empire participates in two DSM programs that are offered on a statewide basis in Arkansas – Energy Efficiency Arkansas and Arkansas Weatherization Program. These are “Quick Start” programs as categorized under the general list of initial program categories as defined in the Energy Efficiency Rules Docket No. 06-004-R Order 18. In addition, since October 2007, Empire has offered its Arkansas customers the opportunity to participate in the C&I Prescriptive Rebate program and the Air Conditioning Tune-Up program. In July 2009, Empire proposed adding the Air Conditioning Replacement Rebate and the Programmable Setback Thermostat to the Arkansas portfolio. These additions plus the C&I Interruptible Program were approved for implementation beginning January 2010.

ES.10 Supply-Side Resources

The future supply-side resources considered by Empire over the IRP’s twenty-year planning horizon include both conventional and renewable resources. A variety of conventional resources were examined in the course of preparing this IRP. These resources included supercritical coal, combustion turbine (CT), combined cycle (CC), nuclear (PPA only), distributed generation, and integrated gasification combined cycle (IGCC). Empire examined a range of renewable resources as well. These included wind, biomass (poultry waste, landfill gas and others), and solar thermal. Residential solar PV was examined as one of the DSM options.

ES.11 Development of Preferred Plan

Both DSM and supply-side resources were considered as available resources in this IRP. The integration and risk analysis proceeded in three phases. During Phase 1 (capacity expansion modeling), specific optimized resource plans that resulted in the lowest present value of revenue requirements (PVRR) were developed for each of 17 different scenarios with a capacity expansion model. Each set of resources was developed specifically to perform the best under the assumptions made about the possible future for each plan. These cases or plans are not directly comparable since the assumptions about the future varied significantly between the plans.

During Phase 2 (stochastic analysis), each plan was subjected to decision analysis (with the critical uncertain factors) with full financial modeling over the planning horizon. These stochastic runs generated 72 endpoints for each of the 17 plans. The results and data points from the decision tree were then used in Phase 3 (risk analysis). In this phase, risk profiles and tornado charts were developed across all plans. All of these analyses were considered by Empire’s decision makers during the development of the preferred plan. The preferred plan represents a balance between the planning objectives, planning risks, and financial impacts examined using the deterministic, stochastic, and risk analyses.

Resource assumptions made for the base case, most of which are common to other cases, except where specified, include:

1) The expiration of the Westar contract for 162 MW.
2) An ownership share of 7.52% (approximately 50 MW) in the coal-fired Plum Point generating unit. The unit met in-service criteria on August 12, 2010.
3) A 50 MW Plum Point PPA (with the option to convert to ownership in 2015).
4) A 12% (approximately 102 MW) ownership share in Iatan 2 (scheduled to begin operation in the fall of 2010).
5) The assumption that five percent of any new wind capacity would count towards the capacity reserve margin.
6) The retirement of Riverton 7 and 8 coal-fired units (92 MW) in December 2014 except for the cases in which the units are converted to natural gas in January 2015. For those cases in which the units are converted to natural gas, they are assumed to retire in December 2018.
7) The Asbury 2 coal-fired unit (17 MW) is assumed to retire in December 2014 concurrent with the addition of the Asbury AQCS equipment.
8) Asbury AQCS installed except in those cases in which this unit is assumed to retire in December 2014.

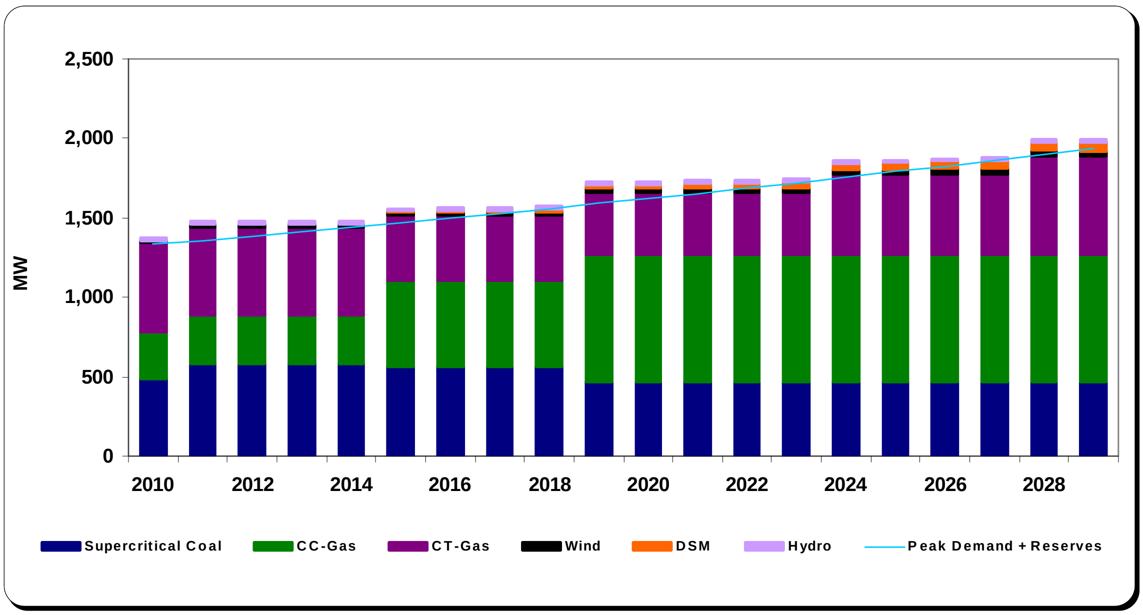
With these supply-side resource decisions and implementation of the slate of DSM programs, Empire's planning reserve margins appear to be satisfied until the 2015 timeframe using the base load forecast in this IRP.

IRP cases were developed and analyzed in this IRP filing for the following 17 sets of future assumptions.

1. Base Assumptions (all resources)
2. Base Assumptions (no future coal)
3. Base Assumptions (no future coal and no DSM)
4. Base Assumptions (Riverton 7&8 to gas in 2015, no future coal)
5. Base Assumptions (retire Asbury 2015, no future coal)
6. Base Assumptions (retire Asbury 2015, convert Riverton 7&8 to gas, no future coal)
7. Base Assumptions without Monett load
8. Base Assumptions without Monett load (no future coal)
9. No CO_2 tax with correlated market and fuel prices
10. Low CO_2 tax with correlated market and fuel prices
11. High CO_2 tax with correlated market and fuel prices
12. High CO_2 tax with correlated market and fuel prices (no future coal)
13. Base assumptions with high load
14. Base assumptions with low load
15. High fuel and market prices – base CO_2
16. Low fuel and market prices – base CO_2
17. Base assumptions with no future coal option, all DSM programs passing base cost assumptions

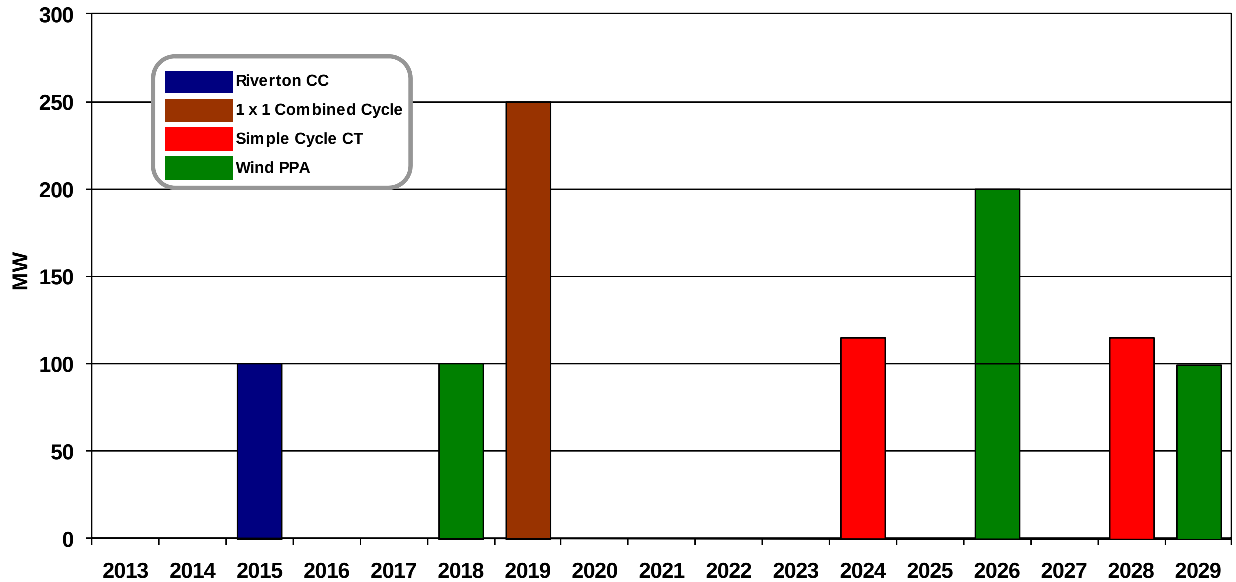
The examination of the seventeen plans led to a set of resource additions, supply-side and demand-side (DSM), over the planning horizon that constitutes Empire's preferred plan. Figure ES-4 shows the supply-side and DSM resources in the preferred plan. Figure ES-5 shows only the new supply-side resources added over the planning horizon in the preferred plan. Figure ES-6 shows the DSM programs selected in the preferred plan.

Figure ES-4
Existing and Preferred Plan Proposed New Resources



(Source: Ventyx)

Figure ES-5
Proposed New Supply-Side Resources in Preferred Plan



(Source: Ventyx)

The additional supply-side resources contemplated in the Preferred Plan, as shown in Figures ES-5, include the conversion of Riverton 12 to a combined cycle unit in 2015, 100 MW of wind in 2018, a new 250-MW combined cycle unit in 2019, new simple cycle CTs in 2024 and 2028, and replacement wind PPAs in 2026 and 2029 when the Elk River and Meridian Way wind PPAs expire. Riverton 7 and 8 would be converted to natural gas in 2015 and continue to operate through 2018. Riverton 9 would retire at the same time as Riverton 7 and 8 retire. AQCS would be installed on Asbury and, simultaneously, Asbury 2 would be retired. The depreciation treatment for both Asbury and Riverton would be determined.

Figure ES-6
Preferred Plan – Proposed New Demand-Side Management Programs

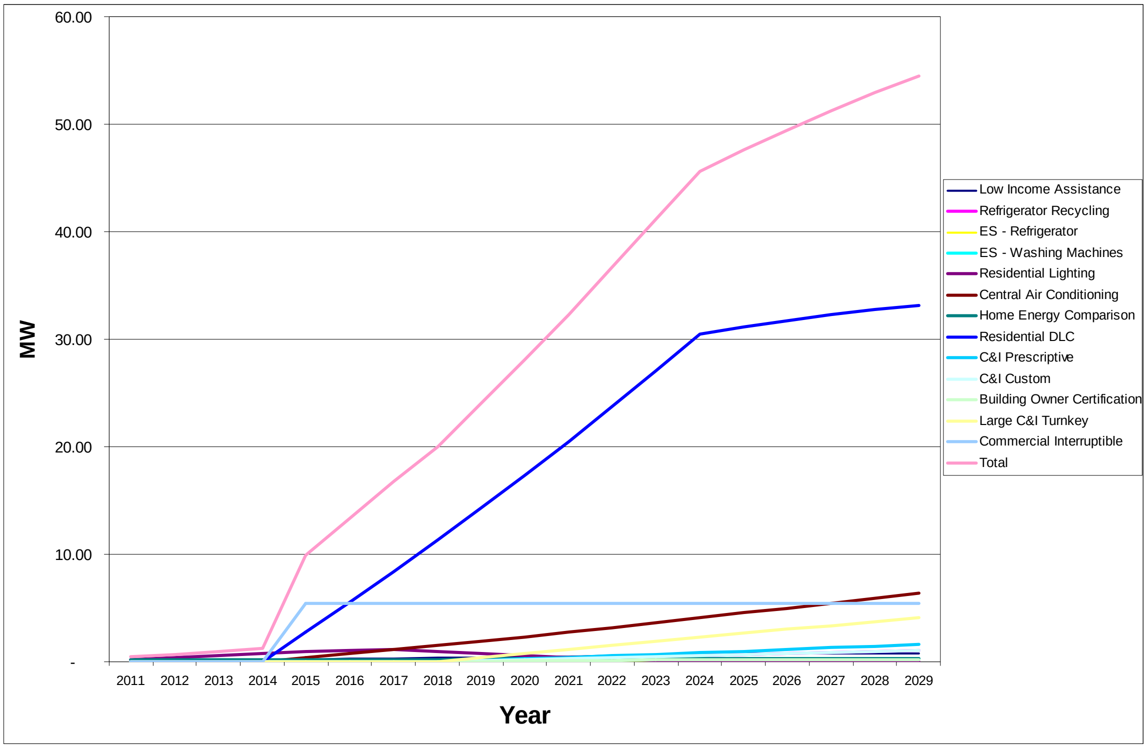


Table ES-4 details the supply-side and DSM resources that in total constitute the resources in the preferred plan.

Table ES-4
Empire's Preferred Plan – Proposed Changes to Existing Resources, New DSM and New Supply-Side Resources

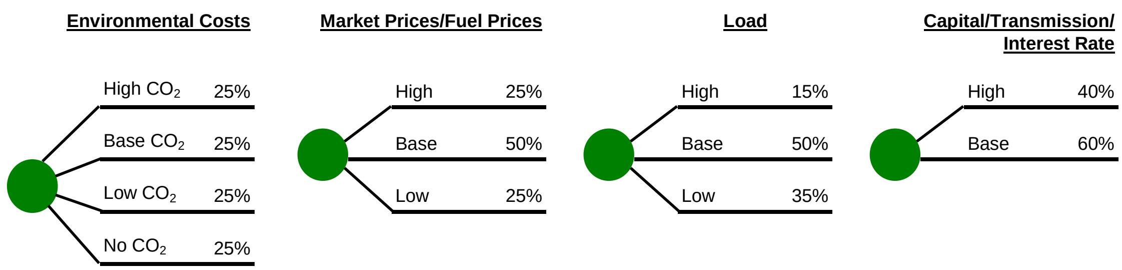
Resource	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Changes to Existing Resources																				
						Riv 7&8 to gas; Asbury AQCS (unit 2 retires); Riv 12 part of Riv CC			Riv 7&8 retire; Riv 9 retires							Elk River Wind PPA expires			Meridian Way Wind PPA expires	
New Supply-Side Resources (MW)																				
	Plum Point 100	Iatan 2 102				Riv CC 100			Wind 100	1 x 1 CC 250					CT 115		Wind 200		CT 115	Wind 100
New Demand-Side Resources (MW)																				
Low Income		0.04	0.08	0.13	0.17	0.22	0.26	0.31	0.36	0.41	0.46	0.52	0.57	0.62	0.67	0.72	0.74	0.75	0.75	0.76
Refrig Recy										0.09	0.18	0.27	0.36	0.46	0.56	0.66	0.76	0.87	0.98	1.00
ES-Refrig										0.02	0.04	0.06	0.09	0.11	0.13	0.15	0.18	0.20	0.23	0.26
ES-WM		0.02	0.03	0.05	0.07	0.08	0.10	0.12	0.14	0.16	0.18	0.20	0.22	0.24	0.26	0.28	0.28	0.29	0.29	0.29
Res Light		0.19	0.39	0.58	0.76	0.91	1.04	1.18	0.99	0.79	0.59	0.42	0.27	0.14						
CAC						0.36	0.74	1.12	1.51	1.91	2.32	2.75	3.18	3.62	4.08	4.53	4.99	5.44	5.90	6.35
Home Ener Comp	0.20	0.20	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Res DLC						2.72	5.50	8.36	11.29	14.29	17.36	20.51	23.74	27.06	30.45	31.13	31.74	32.28	32.74	33.14
C&I Pres										0.13	0.26	0.40	0.54	0.68	0.83	0.98	1.14	1.30	1.47	1.64
C&I Cust										0.09	0.19	0.28	0.37	0.46	0.56	0.65	0.74	0.83	0.93	1.02
BOC										0.03	0.07	0.10	0.14	0.18	0.19	0.20	0.20	0.21	0.22	0.23
Large C&I Turnkey										0.38	0.75	1.13	1.50	1.88	2.25	2.63	3.00	3.38	3.75	4.13
Comm Int						5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43
TOTAL DSM		**0.45**	**0.70**	**0.97**	**1.21**	**9.94**	**13.31**	**16.75**	**19.96**	**23.98**	**28.09**	**32.31**	**36.66**	**41.13**	**45.66**	**47.62**	**49.46**	**51.23**	**52.95**	**54.49**

Plum Point 100 MW is the total of ownership and PPA. As Iatan 2 is not available for the 2010 summer peak, it is reflected as a resource addition in 2011. Five percent of wind capacity is counted for reserve purposes. When Asbury AQCS is completed, Asbury 2 is retired. Riverton 7, 8 & 9 retire 12/31/2018. Elk River PPA expires 12/15/2025. Meridian Way PPA expires 12/23/2028.

ES.12 Uncertainty Analysis and Risk Profiles

Risk profiles were prepared in order to quantify the risks associated with the preferred plan and the other plans. These risk profiles are cumulative probability distributions of the present value of revenue requirements (PVRR) developed across a range of uncertainties that reflect the critical uncertain factors associated with the future. The decision tree (Figure ES-7) developed for the uncertainty analysis examined many uncertain variables for each plan (critical uncertain factors). The uncertainties can be grouped into four main categories: 1) environmental costs, 2) market and fuel prices, 3) load forecast, and 4) capital and transmission costs and interest rates. For environmental costs, the base contains higher costs than the low and no CO_2 cost cases and lower costs than the high case. All environmental costs were correlated to the assumed CO_2 costs. For the market prices/fuel prices and load, the uncertainties reflect a high and low around a base. All high, low and base market and fuel prices were correlated with the corresponding CO_2 costs. For capital and transmission costs and interest rates, only a base and high level were examined. The critical uncertain factors are shown in Figure ES-7. The probabilities assigned to each branch were developed by the IRP team in conjunction with Empire's senior management and reflect knowledge of the Empire system and the application of professional judgment.

Figure ES-7
Critical Uncertain Factors



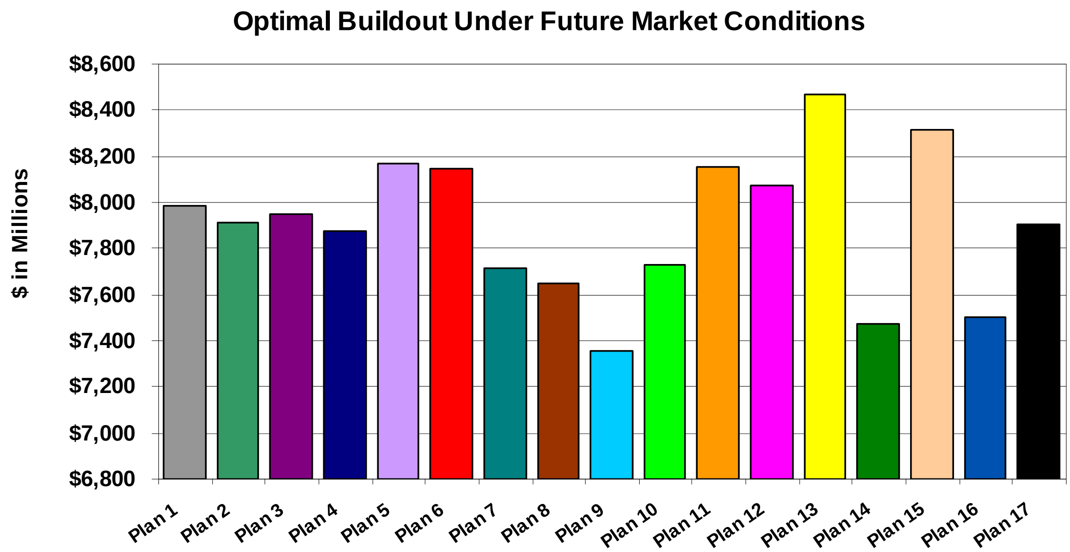
(Source: Ventyx)

ES.13 Comparison of the Plans

Not all cases can be directly compared due to their significantly different base assumptions. Those cases that are variations on the base assumptions and all cases that utilize the base CO_2 cost assumptions can be compared one versus the other. However, these plans do not directly compare with alternate scenarios that are based on significantly different CO_2 cost or load forecast assumptions. Yet plans with assumptions other than the base assumptions were important contingency plans to analyze to assist Empire in planning for its future.

The supply-side and demand-side resource selections for each alternate plan were optimized to perform well for the assumptions of that particular plan. Figure ES-8 shows the PVRR for each plan based on the assumption that the futures that they were developed to address would actually occur.

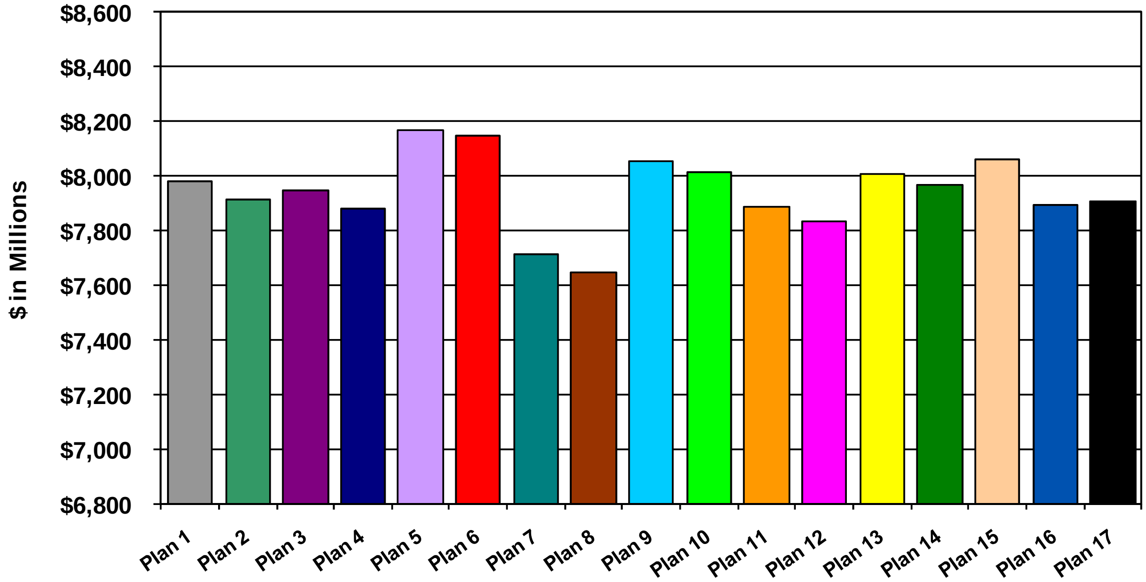
Figure ES-8



1. Base Assumptions (all resources)
2. Base Assumptions (no future coal)
3. Base Assumptions (no future coal and no DSM)
4. Base Assumptions (Riverton 7&8 to gas in 2015, no future coal)
5. Base Assumptions (retire Asbury 2015, no future coal)
6. Base Assumptions (retire Asbury 2015, convert Riverton 7&8 to gas, no future coal)
7. Base Assumptions without Monett load
8. Base Assumptions without Monett load (no future coal)
9. No CO_2 tax with correlated market and fuel prices
10. Low CO_2 tax with correlated market and fuel prices
11. High CO_2 tax with correlated market and fuel prices
12. High CO_2 tax with correlated market and fuel prices (no future coal)
13. Base assumptions with high load
14. Base assumptions with low load
15. High fuel and market prices – base CO_2
16. Low fuel and market prices – base CO_2
17. Base assumptions with no future coal option, all DSM programs passing base cost assumptions

To compare plans and to comply with Empire's interpretation of the IRP rule, all 17 of the plans were each analyzed with the base assumptions of the critical uncertain factors to see how they would perform under those conditions (deterministic approach) (Figure ES-9). For example, in Plan 9, an optimal resource plan is developed assuming that no CO_2 tax was enacted. Yet, the base assumptions include a CO_2 tax. Figure ES-9 shows how well that Plan 9 would perform on a PVRR given the base case assumptions as well as the results for each other plan taking this same approach.

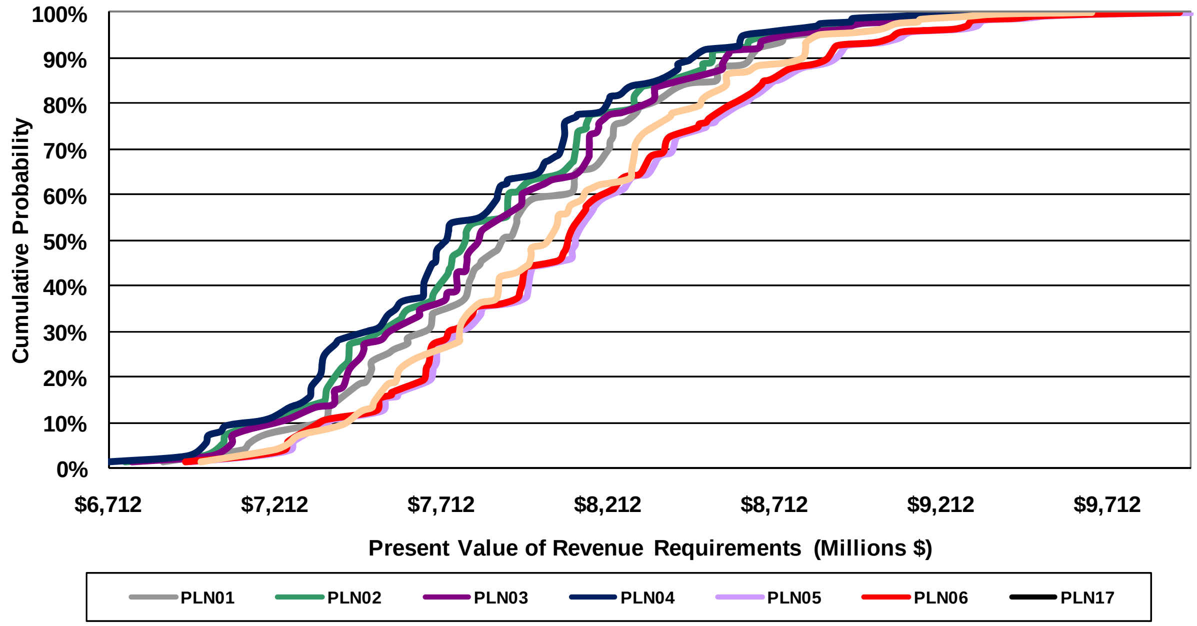
Figure ES-9
All Scenarios – 20-Year Deterministic PVRR (2010-2029)



All of the cases were also analyzed stochastically in a decision tree by subjecting each plan to all of the levels of the critical uncertain factors, creating a 72 endpoint tree for each of the 17 plans. This analysis results in risk profiles for each plan.

The risk profiles for the cases that utilize the base case assumptions (and that can be compared one with the other) are shown on Figure ES-10. The risk profile for Plan 4 can be seen to be the left-most curve on the figure and the one with the steepest profile, which translates into the lowest risk. Plan 4 was selected by Empire as the Preferred Plan.

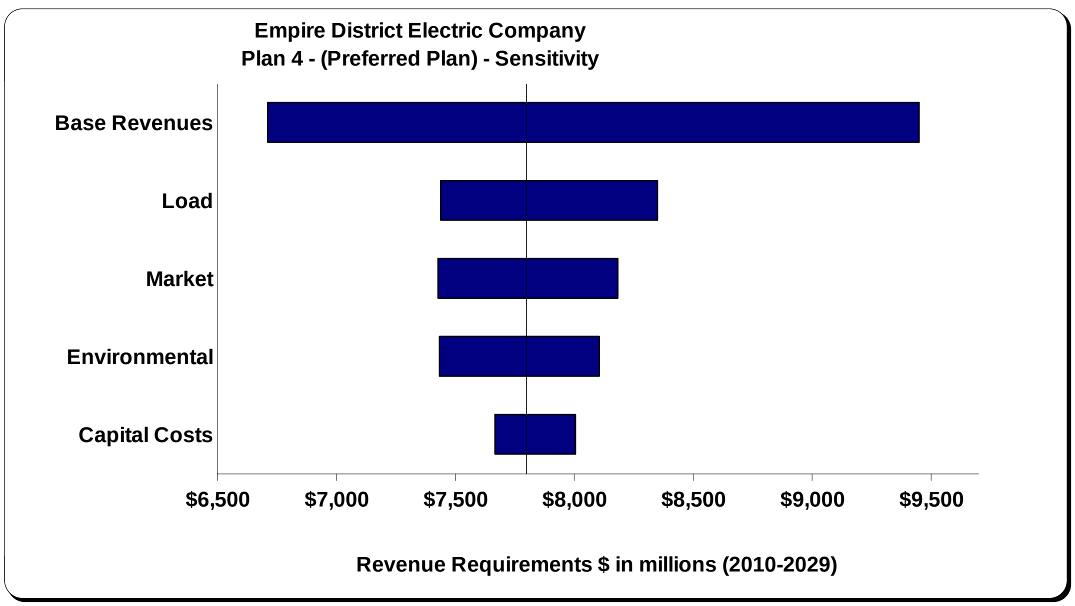
Figure ES-10
All Base Scenarios – Risk Profiles (2010-2029)



(Source: Ventyx)

The tornado chart for the Preferred Plan, Figure ES-11, demonstrates that the primary drivers of PVRR uncertainty are the environmental, load forecast, and market/fuel prices. The top two drivers of uncertainty change between plans, but the capital/transmission/interest driver is always the least significant risk driver for all cases.

Figure ES-11
Preferred Plan – Tornado Chart



(Source: Ventyx)

1.0 Introduction

1.1 Organization of the Report

The report is organized into various volumes as follows:

Volume I:	Executive Summary, Introduction
Volume II:	Load Analysis and Forecasting (4 CSR 240-22.030)
Volume III:	Supply-Side Resources Analysis (4 CSR 240-22.040)
Volume IV:	Demand-Side Resources Analysis (4 CSR 240-22.050)
Volume V:	Integrated Resource Analysis (4 CSR 240-22.060) and Risk Analysis and Strategy Selection (4 CSR 240-22.070)

1.2 Follow up to the 2007 IRP Unanimous Stipulation and Agreement (dated May 6, 2008)

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

- Load Analysis and Forecasting: Include a summary of the economic outlook of Empire's service territory that includes conditions that encourage and impede growth and how the economic drivers that Empire has selected for each of its models capture these conditions. The economic driver descriptions will include 1) graphs and/or tables of historical and forecasted data; 2) the statistical rationale for selecting the economic variables used in the regression analysis; and 3) a discussion of the effect of using the economic indicator in the model.
- Supply-Side Resource Analysis: Any costs not listed separately shall be identified with documentation that those costs are included in the total costs.
- Supply-Side Resource Analysis: Consider and analyze upgrades to all existing plant and detail that analysis.
- Supply-Side Resource Analysis: Cost rankings for supply-side resources will be provided unless Empire is granted a waiver from this requirement or there is a change in this part of the IRP rule.
- Supply-Side Resource Analysis: Consider other long-term PPAs [in addition to wind] as candidate resources.
- Supply-Side Resource Analysis: Identify critical uncertain factors for annual fixed and variable operation and maintenance costs, describe why these costs were or were not deemed critical factors unless Empire is granted a waiver from this requirement or there is a change in this part of the IRP rule.
- Supply-Side Resource Analysis: Analyze dispatchable renewable resources such as landfill gas generation and additional biomass technologies; solar-based non-dispatchable renewable technologies such as photovoltaic (PV) and solar thermal generation resources; and potential energy efficiency improvements of existing resources.

- Supply-Side Resource Analysis: If any resource options are eliminated during the screening phase, the Company will provide an explanation of the process used to eliminate it.
- Demand-Side Resource Analysis: Analyze renewable energy sources and energy technologies that substitute for electricity at the point of use.
- Demand-Side Resource Analysis: Conduct an Appliance Saturation Survey, followed by a Commercial End-Use Inventory prior to the next IRP filing. Identify market segments unless granted a waiver from this requirement or there is a change in this part of the IRP rule.
- Demand-Side Resource Analysis: Analyze the interaction between end-use measures unless granted a waiver from this requirement or there is a change in this part of the IRP rule.
- Demand-Side Resource Analysis: Consider a broader universe of DSM programs, including joint delivery programs where Empire cooperates with gas utilities that operate in its service territory.
- Demand-Side Resource Analysis: All demand-side programs that pass demand-side screening will be included in at least one alternative resource plan unless Empire is granted a waiver from 4 CSR 240-22.050(7)(F) or there is a change in this part of the IRP rule.
- Demand-Side Resource Analysis: Outline the menu of energy efficiency and energy measures. For each measure listed, the measure's (1) base technology, (2) base efficiency definition, (3) efficient technology, and (4) efficient technology definition will be included.
- Integrated Resource Analysis: Empire's analysis will include an evaluation of the potential load building implications for all existing and proposed demand-side programs that include compensation for end-use measures where load building may occur.
- Integrated Resource Analysis: Contingency plans will be subjected to the same risk analysis as other alternate resource plans.
- Integrated Resource Analysis: Model demand-side resources (both energy efficiency resources and demand response resources) in some of its alternative resource plans for the entire planning horizon (i.e., 20 years) over which the costs and benefits of alternative resource plans are evaluated. At least two portfolios of demand-side resources (including both moderate and aggressive portfolios) will be modeled in some of the alternative resource plans.
- Risk Analysis and Strategy Selection: Prior to the next filing, work with signatory parties to clarify what is required of a preliminary sensitivity analysis prior to conducting such an analysis unless Empire is granted a waiver from this requirement or there is a change in this part of the IRP rule. The waiver request will include a discussion of why Empire believes the information is not necessary.
- Risk Analysis and Strategy Selection: Document the range of critical uncertain factors that define the limits within which the preferred resource plan has been judged to be appropriate unless Empire is granted a waiver from this requirement or there is a change in this part of the IRP rule.
- Risk Analysis and Strategy Selection: (1) clearly identify the uncertain factors that it determines to be critical to the performance of its alternative resource

plans; and (2) document the subjective assessments of probabilities by Empire decision-makers for the likelihood of adverse outcomes for uncertain factors that are critical to the performance of the various alternative resource plans. The names and positions of these decision-makers will also be documented.

- Risk Analysis and Strategy Selection: Subject contingency plans to the same risk analysis that was applied to other alternate resource plans. This approach will further study the contingencies of more stringent environmental cases.
- Risk Analysis and Strategy Selection: Specify a set of contingency options for the critical uncertain factors as part of an officially adopted resources acquisition strategy unless Empire is granted a waiver from 4 CSR 240-22.070(9)(D) or there is a change in this part of the IRP rule.
- Risk Analysis and Strategy Selection: For each critical uncertain factor, develop a contingency option that would be triggered by extreme values for that critical uncertain factor, and for each unique combination of critical uncertain factors that is deemed by Empire to require separate contingency analysis, develop a contingency option that would be triggered by extreme values for that unique combination of critical uncertain factors, or seek a waiver of this rule if Empire believes it will provide an alternative analysis that will adequately examine critical uncertain factors and appropriate responses should any one, or a combination of extreme outcomes, occur.

Each requirement is addressed in its appropriate Volume. A summary table is provided in each volume that shows where in that volume the requirement has been addressed.

2.0 State of the Industry

Planning for future generating resources in the electric utility industry involves the consideration and evaluation of many uncertainties. Those uncertainties have increased in number and magnitude over the last several decades. Empire has considered the impacts of, and will discuss in this section of its 2010 IRP, uncertainties that include the future of coal-fired generation, nuclear power plant technologies, smart grid, plug-in hybrid electric vehicles, Energy Efficiency Resource Standards (EERS), and decoupling. The future of coal-fired generation discussion touches on climate change legislation, carbon capture and sequestration technologies, and environmental regulatory requirements.

2.1 The Future of Coal-Fired Generation

For many years, most of the baseload energy needs in this country has been provided by coal-fired generation. As a fuel, coal has many merits:

- it is dense (meaning it has a high heating value in a compressed space)
- there are extensive and efficient supply chains that have been built over its many years of use
- it is relatively low cost and has experienced much less price volatility than other fuels, particularly natural gas

Coal is also quite abundant in this country (the estimated supply is hundreds of years of usage), helping to ensure national energy security.

One of the newer issues surrounding coal as a fuel for electricity generation is that it produces more carbon dioxide (CO_2) emissions per unit of energy output than any other fuel – about twice as much as natural gas. Today the future of coal-fired generation for electric utilities is a major uncertainty. Coal faces competitive pressure from natural gas in the short term and in the long term from renewable resources or other emerging technologies. But coal plants continue to be built in developing nations particularly China. Some sources report that China is on the average adding one new coal plant per week.

It took many decades to build up the current infrastructure of coal-fired power plants in the United States, so existing coal-fired generation will continue to be a large producer of energy during the 20-year planning horizon of this IRP and beyond. Carbon capture and sequestration (CCS) has yet to be proven on a commercial scale and may or may not be practical in any given location depending on the geology at the site.

As a result of potential greenhouse gas legislation, this IRP considers environmental costs (which include possible CO_2 costs) as a critical uncertain factor. As a result of the uncertainty of the future of coal-fired generation, some alternate plans assume that no future new coal-fired units will be built during the planning horizon.

2.1.1 Climate Change Legislation

The effects of greenhouse gases on the atmosphere and on the Earth's climate have been a subject of debate in the U.S. and worldwide for many years. On May 19, 2010, the National Research Council, an arm of the National Academies, issued three reports that concluded global climate change is occurring and that it is caused in large part by human activities. The reports recommend some form of carbon pricing system as the most cost-effective way to reduce emissions. The reports posit that cap-and-trade, taxing emissions or some combination of the two could provide the needed incentive to reduce the carbon emissions. The reports further state that major technological and behavioral changes will be required; business as usual will not address the climate change issue. Among those changes, the reports recommend the capturing and sequestering of CO_2 from power plants and factories as well as scrubbing CO_2 directly from the atmosphere.

How these reports will be translated into regulation and laws at the local, state and national levels remain to be seen, continuing this uncertainty in the planning period of Empire's IRP. Empire cannot predict if any particular carbon mitigation strategy will be enacted into law or when such might occur. As a result of this continuing uncertainty and to anticipate a broad range of future environmental regulatory strategies, Empire considered four levels of potential carbon regulation in the current IRP including a scenario where no carbon cost legislation was enacted. In addition, Empire included environmental costs in the critical uncertain factors to be examined.

2.1.2 Carbon Capture and Sequestration Technologies[4]

Carbon capture and sequestration (CCS) technologies are currently being researched and tested in an effort to remove CO_2 from the atmosphere. Carbon capture is defined as the separation and entrapment of CO_2 from large stationary sources including power plants, cement manufacturing, ammonia production, iron and non-ferrous metal smelters, industrial boilers, refineries, and natural gas wells. Carbon sequestration means the capture and secure storage of CO_2 that would otherwise be emitted to or remain in the atmosphere. CO_2 can also be removed from the atmosphere through what is termed "enhancing natural sinks" by increasing its uptake in soils and vegetation (reforestation) or in the ocean (iron fertilization).

CO_2 capture processes fall into three general categories: (1) flue gas separation, (2) oxy-fuel combustion in power plants, and (3) pre-combustion separation. Each process has associated economic (cost) and energy (kWh) penalties.

For flue gas separation, the capture process is typically based on chemical absorption where the CO_2 is absorbed in a liquid solvent by formation of a chemically bonded compound. The captured CO_2 is used for various industrial and commercial processes such as the production of urea, foam blowing, carbonated beverages, and dry ice

[4] Howard Herzog and Dan Golomb, "Carbon Capture and Storage from Fossil Fuel Use," as published in the *Encyclopedia of Energy*, 2004.

production. Other processes being examined for CO_2 capture from the flue gas include membrane separation, cryogenic fractionation, and adsorption using molecular sieves.

An alternative to flue gas separation is to burn the fossil fuel in pure or enriched oxygen. The flue gas will then contain mostly CO_2 and water vapor. The water vapor can be condensed and the CO_2 can be compressed and piped directly to a storage site. Whereas for flue gas separation, the separation took place after combustion, now the separation occurs in the intake air where oxygen and nitrogen need to be separated. Just the air separation unit can impose a 15% efficiency penalty. Pilot scale studies have indicated that this method of carbon capture can be retrofitted on existing pulverized coal units.

Pre-combustion capture is usually applied in coal gasification combined cycle power plants. The process involves gasifying the coal to produce a synthetic gas. That gas reacts with water to produce CO_2 and hydrogen fuel. The hydrogen fuel is used in the turbine to produce electricity and the CO_2 is captured.

Once the CO_2 is captured, it must be stored in a manner in which it will not be emitted back into the atmosphere. Such storage needs to be: 1) long, preferably hundreds to thousands of years, 2) at minimal cost including transportation to the storage site, 3) with no risk of accident, 4) with minimal environmental impact, and 5) without violating any national or international laws or regulations. Potential storage media include geologic sinks and the deep ocean. Geologic sinks include deep saline formations – subterranean and sub-seabed), depleted oil and gas reservoirs, enhanced oil recovery, and unminable coal seams. Deep ocean storage includes direct injection into the water column at intermediate or deep depths.

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

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

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

Service Commission, Missouri Public Utility Alliance, and the U.S. Environmental Protection Agency (EPA) Region VII.

For purposes of this IRP, Empire assumed CCS has not progressed enough to be a viable alternative for this IRP during the entire twenty-year planning horizon.

2.1.3 Environmental Regulatory Requirements

Empire personnel are closely monitoring environmental regulations and requirements to determine what actions needed to be undertaken to ensure compliance and to understand the costs associated with that compliance. Among other issues, Empire is currently tracking issues relating to ozone; sulfur dioxide (SO_2); nitrogen dioxide (NO_2); the Clean Air Interstate Rule (CAIR) and its impending replacement rule, the Clean Air Transport Rule (CATR); water; particulate matter, specifically for 2.5 micrometers ($PM_{2.5}$); the Coal Combustion Residuals (CCR) rule relating to ash; mercury and hazardous air pollutants (Hg/HAPS); and carbon dioxide (CO_2), (see Figure 2-1[5]). The information gathered is discussed with senior management.

The uncertainty related to the myriad of rules expected from the U.S. Environmental Protection Agency (EPA) is large. The American Public Power Association (APPA) projects that the coal-fired power sector will see near-constant retrofits from 2012 through 2018, competition for scarce engineering and construction services and equipment, large-scale unit retirements, possible shortfalls in reserve margin requirements, an increase in natural gas generation, and a worrisome chance that financial resources could be misallocated and investments left stranded.[6]

APPA believes that the EPA hopes to force closure of 50% of the fleet of coal-fired generating units in the U.S. in the next 10 years which would reduce the CO_2 emissions by a commensurate 50%. The cost of such a transition is in the hundreds of billions of dollars.[7]

To address these types of concerns in this IRP, Empire modeled the Asbury AQCS and the retirement of some existing coal-fired generation, and evaluated some cases in which no new coal-fired generation could be built in the planning horizon.

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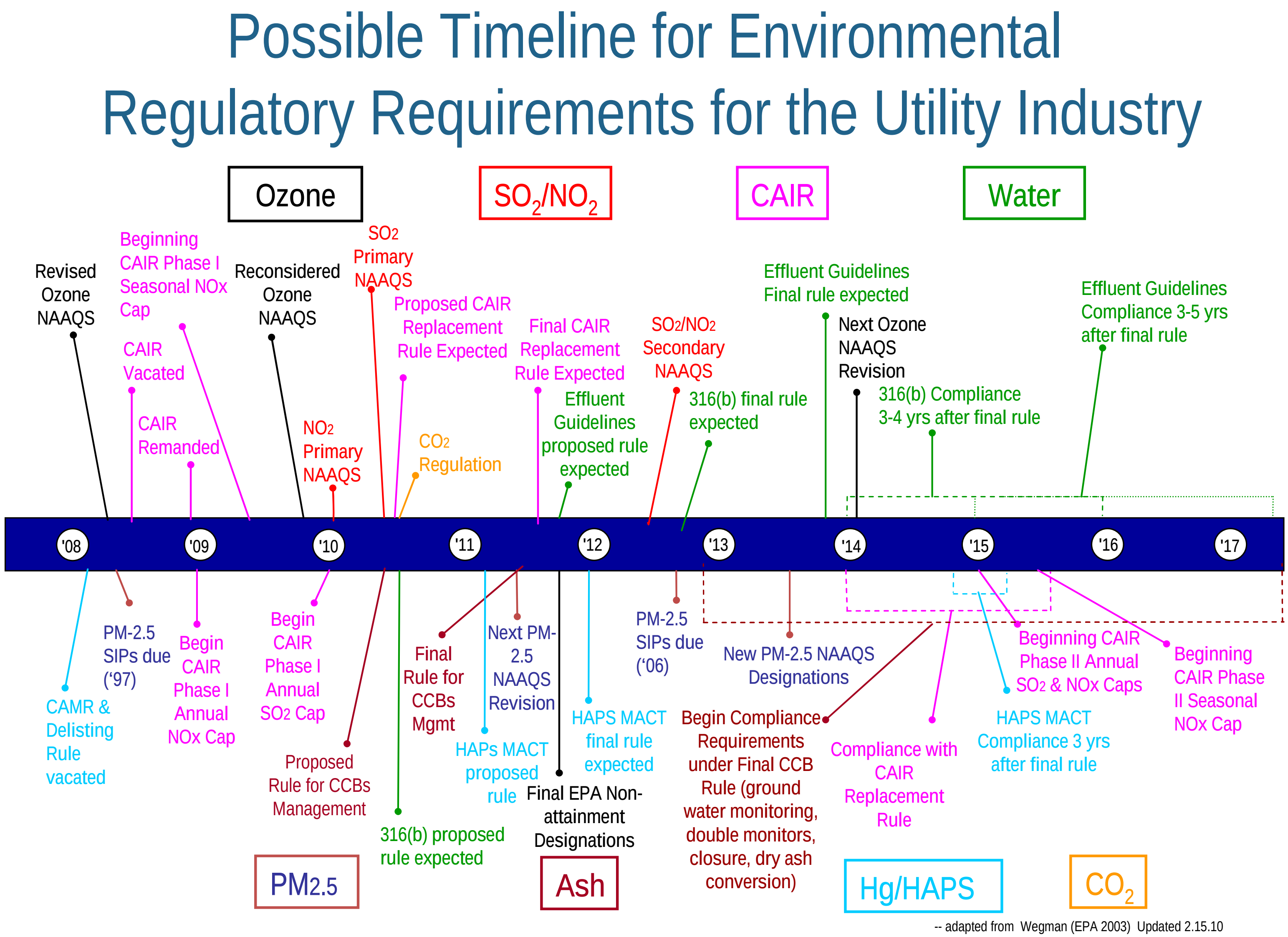
[5] "Generating Buzz," *Power Engineering*, July 2010, p. 80.
[6] Eric Wagman, "Expect a Mess as EPA Rules Take Hold," *Power Engineering*, July 2010, p. 4.
[7] Ibid.

Figure 2-1


Possible Timeline for Environmental Regulatory Requirements for the Utility Industry
Ozone
SO_2/NO_2
CAIR
Water
Revised Ozone NAAQS
Beginning CAIR Phase I Seasonal NOx Cap
CAIR Vacated
CAIR Remanded
Reconsidered Ozone NAAQS
NO2 Primary NAAQS
SO2 Primary NAAQS
Proposed CAIR Replacement Rule Expected
CO2 Regulation
Final CAIR Replacement Rule Expected
Effluent Guidelines proposed rule expected
SO2/NO2 Secondary NAAQS
316(b) final rule expected
Effluent Guidelines Final rule expected
Next Ozone NAAQS Revision
316(b) Compliance 3-4 yrs after final rule
Effluent Guidelines Compliance 3-5 yrs after final rule
'08
'09
'10
'11
'12
'13
'14
'15
'16
'17
CAMR & Delisting Rule vacated
PM-2.5 SIPs due ('97)
Begin CAIR Phase I Annual NOx Cap
Begin CAIR Phase I Annual SO2 Cap
Proposed Rule for CCBs Management
316(b) proposed rule expected
Final Rule for CCBs Mgmt
Next PM-2.5 NAAQS Revision
HAPs MACT proposed rule
Final EPA Non-attainment Designations
HAPS MACT final rule expected
PM-2.5 SIPs due ('06)
New PM-2.5 NAAQS Designations
Begin Compliance Requirements under Final CCB Rule (ground water monitoring, double monitors, closure, dry ash conversion)
Compliance with CAIR Replacement Rule
Beginning CAIR Phase II Annual SO2 & NOx Caps
HAPS MACT Compliance 3 yrs after final rule
Beginning CAIR Phase II Seasonal NOx Cap
PM2.5
Ash
Hg/HAPS
CO_2
-- adapted from Wegman (EPA 2003) Updated 2.15.10

2.2 Nuclear Power Plant Technologies

The nuclear power plant fleet in the U.S. has been generating electricity for many decades with an associated steady increase in productivity. However, no new nuclear units have been built in the U.S. since the 1990s. Several projects, each in the range of 1,000 MW, are currently in advanced design and applications for combined construction and operating licenses for brownfield units at the sites of existing operating nuclear power plants are awaiting approval at the U.S. Nuclear Regulatory Commission (NRC). The earliest of these units, the Vogtle project, is expected to be in operation in the 2017-2018 timeframe. The Vogtle 3 and 4 project has received a loan guarantee and favorable rate treatment during construction from the utilities commission in Georgia.

Many concerns are associated with the resurgence of nuclear power as a generation resource. The first is the cost. During the last cycle of nuclear power plant building, the costs rose to exorbitant levels and some regulatory commissions did not allow portions of those nuclear costs into utility rates. An additional concern is related to personnel and worldwide manufacturing capability. There are a limited number of trained engineers, skilled craft laborers, and other personnel to design, build, and staff these units. On the manufacturing side, there is only one steel company in the world with the capability to build the containment vessel, and that firm is in Japan.[8] In the U.S., there are still waste disposal issues including the recent stoppage of work on the Yucca Mountain nuclear storage facility. This means that there is no central repository for nuclear waste in the country and no current efforts are underway to reprocess nuclear materiel.

To address the cost concerns, the concept of small modular reactors (SMR), in the range of 70-210 MW apiece is being investigated. Some of these units are already under construction in China and Russia. A consortium of U.S. electric utilities including the Tennessee Valley Authority, First Energy, and Oglethorpe Power are working with Babcock & Wilcox to get a 125-MW SMR, called the mPower, approved for commercial use in the U.S.[9] Because of its smaller size, some concerns have been raised and will need to be addressed regarding nuclear proliferation issues. In addition, these SMRs have yet to proceed through the regulatory approval process.

During the previous iteration of nuclear power plant additions, significant public and political opposition arose regarding the siting and location of nuclear units near metropolitan areas and the difficulty seen in evacuation during emergencies. Although political and public opposition appears to have abated in the last twenty to thirty years and there currently appears to be general public support for nuclear power, only as units go through the regulatory approval process and then actual construction will the true situation be revealed with regard to public and political support.

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[8] Eric Spiegel and Neil McArthur with Rob Norton, *Energy Shift: Game-Changing Options for Fueling the Future*, McGraw Hill, New York, 2009, p. 123.

[9] "Small Reactors Generate Big Hopes, Rebecca Smith, *The Wall Street Journal*, February 18, 2010, http://online.wsj.com/article/SB10001424052748703444804575071402124482176.html. "Downsizing Nuclear Power Plants," Peter Fairley, *IEEE Spectrum*, May 2010, pp. 14-15.

In this IRP, Empire assumed that a nuclear PPA, from a unit built by other utilities in the region, would be available no earlier than 2025.

2.3 Smart Grid

The term "Smart Grid" is frequently used in discussions among government agencies, equipment manufacturers, and the utility industry. However, the definition of that smart grid varies significantly depending on who is leading the discussion. For Empire's purposes in preparing this IRP, Smart Grid will mean integrating the electrical infrastructure with the communications network. This will lead to an automated electric power system that monitors and controls grid activities, ensuring two-way flow of electricity and information between power plants and consumers – and all points in-between. Such an enhanced system will facilitate:[10]

- improved electricity flows from power plants to consumers
- consumer interaction with the grid
- improved response to power demand
- reduced incidence of generation resource outages
- more consistent and reliable power quality
- increased reliability and security
- more efficient overall operation

Some of the technologies that will be required in order for the U.S. to realize this vision for the Smart Grid of the future include:[11]

- Smart meters for advanced measurement
- Integrated two-way communications
- Active customer interface including home area networks with in-home displays
- Meter data management system
- Distribution management system with advanced and ubiquitous sensors
- Distribution geographical information system
- Substation automation including sensors to monitor transformers, relays, digital fault recorders, breakers, and station batteries
- Advanced protection and control schemes
- Advanced grid control devices

The enhancements of the electricity infrastructure in this manner are expected to lead to many benefits including active management and control of electricity generation, transmission, distribution and usage in real time; an optimal balance between supply and

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[10] "Smart Grid basics," www.smartgrid.gov/basics. "Wotruba, Bill, "Enabling the Smart Grid," *Power Engineering*, May 2010, p. 52.
[11] Joe Miller, Horizon Energy Group, "The Smart Grid – How do we get there?" http://www.smartgridnews.com/artman/publish/Business_Strategy_News/The_Smart_Grid_How_Do_We_Get_There-452.html.

demand; reduced numbers of outages; more consistent and reliable power quality; increased reliability and security; and more efficient overall operation, among others.[12]

- **Reduced incidence of outages**. Smart grids rely on embedded automation and control devices. Thus energy producers and the operators of the transmission and distribution systems will be able to anticipate, detect, and respond to system problems more quickly than is possible with the technology in place currently.
- **More consistent and reliable power quality**. When supply and demand are more optimally balanced, operation will be leaner and more efficient which in turn leads to higher levels of customer service.
- **Increased reliability and security**. With the capabilities of the enhanced communication system and associated real-time monitoring, power companies will have increased visibility of the entire generation, transmission, and distribution systems and thus an increased ability to resist both physical threats and cyber attacks. Operations that are networked tend to have increased reliability and reduced expensive downtime. The smart grid may also increase redundancy, in turn leading to fewer service disruptions.
- **More efficient overall operation**. The smart grid should reduce bottlenecks and relieve grid congestion. Fewer outages and less congestion should lead to lower costs to customers and, potentially, fewer emissions.

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

2.4 Plug-in Hybrid Electric Vehicles

Electric vehicles, and their associated battery technology, have been under development for several decades. Today's hybrid electric vehicles, available for purchase by the mass market and part of the rental car fleets, have significantly advanced the likelihood that such cars can be a commercial success and not just an oddity. The hybrid electric vehicles recharge themselves as they are still fueled by gasoline or similar fuel. The next step in the evolution of personal transportation appears to be plug-in hybrid electric vehicles (PHEV) and plug-in electric vehicles, which are dependent on advances in battery technology. This evolutionary step could have significant impacts on the electric utility industry.

[12] "Smart Grid basics," www.smartgrid.gov/basics. "Wotruba, Bill, "Enabling the Smart Grid," *Power Engineering,* May 2010, p. 52.

PHEVs will require charging, presumably daily. Without a smart grid, or a smart plug, the PHEVs could recharge during on-peak periods, thus increasing an electric utility's load and potentially causing the need for new generating capacity. A smart plug would know not to begin charging until a utility's off-peak hours.

In addition, PHEVs represent what transmission planners call "mobile loads." This means that the car might be charged at home, at the office, at the mall, or at other locations. Such flexibility for the customer will require accommodation through the design or redesign of the transmission and distribution systems which have yet to occur on any utility system in the country including Empire's. No changes to the load forecast or modifications to the transmission and distribution plans are contained in this IRP as would be necessary to accommodate widespread adoption of PHEVs in Empire's service territory.

2.5 Energy Efficiency Resource Standard

An Energy Efficiency Resource Standard (EERS) (also referred to as Energy Efficiency Portfolio Standard (EEPS) or energy efficiency target) is a mechanism to encourage more efficient generation, transmission, and use of electricity and natural gas. Like a Renewable Portfolio Standard (RPS), an EERS requires utilities to reduce energy use by a specified and typically increasing percentage or amount each year. Some states have a separate EERS and RPS, while other states combine the mechanisms by allowing energy efficiency to meet part or all of an RPS. Efficiency reduction requirements or targets may also be established by state public utility commissions.[13]

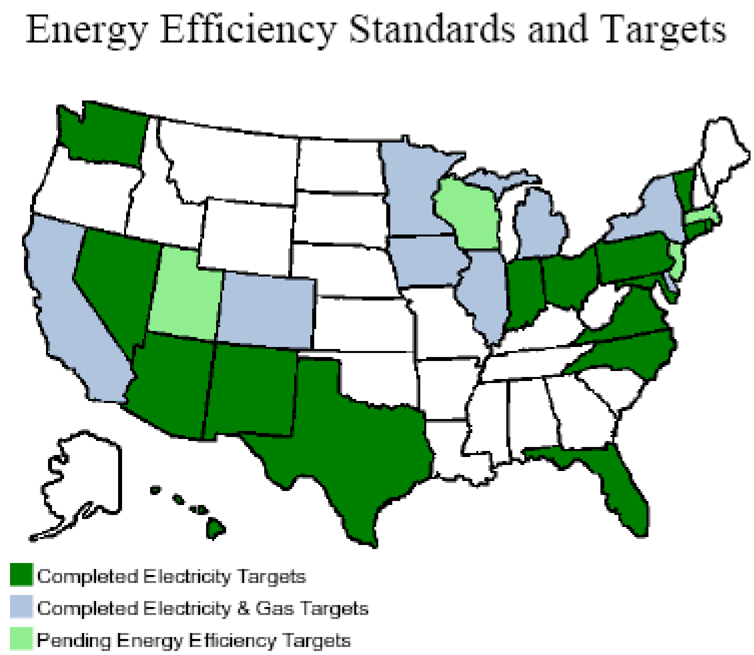
Electricity savings requirements for utilities may include flexibility to achieve the standard through a market-based trading system of energy savings certificates. All EERS include end-use energy savings. In some cases, distribution system efficiency improvements, combined heat and power (CHP) systems and other high-efficiency distributed generation systems are also included. Penalties for non-compliance vary by state.[14]

Legislation has been introduced in Missouri (most recently as SB 983 in the 2010 legislative session), but has not been enacted to date. Empire considered EERS as an uncertain factor, but it was not chosen as a critical uncertain factor since none of the jurisdictions that Empire serves currently has an EERS.

Legislation at the national level has also been introduced, but to date has not been enacted. A map showing EERS status by state is shown in Figure 2-2.

[13] http://www.pewclimate.org/what_s_being_done/in_the_states/efficiency_resource.cfm
[14] http://www.pewclimate.org/what_s_being_done/in_the_states/efficiency_resource.cfm

Figure 2-2



Source:
http://www.pewclimate.org/what_s_being_done/in_the_states/efficiency_resource.cfm

2.6 Decoupling

The reliance of conventional rate recovery methodologies on the amount of kWh sold to customers discourage electric utilities from pursuing energy efficiency and other DSM programs. A variety of methods have been developed and implemented in a number of jurisdictions around the country to both ensure the financial integrity of electric utilities and to encourage conservation and energy efficiency programs. These methods include revenue decoupling, surcharges, and shared savings as well as performance-based ratemaking.

Revenue decoupling unlinks, to some extent, a utility's cost recovery and profitability from sales volume and instead ensures cost recovery through a true-up or other mechanism. Decoupling has been in place for the longest period of time in California. Decoupling began there in 1982, although it was interrupted during the period of time when the state deregulated the electric industry. The allowed revenue amount is adjusted each year to reflect inflation, productivity increases, and increases in the number of customers that the company serves. For California, it appears that decoupling has been successful in having a limited effect on rates while encouraging energy efficiency and conservation initiatives.[15]

[15] "Electric Rate Decoupling in Other States," Kevin E. McCarthy, January 21, 2009, 2009-R-0026, www.cga.ct.gov/2009/rpt/2009-R-0026.htm.

A surcharge, also known as a tariff rider charge, is used by utilities in the western U.S. including PacifiCorp, Avista, Idaho Power, and Puget Sound Energy[16]. The volumetric surcharge is collected via the application of a percentage to the customer bills. The percentage is established through the regulatory process and is typically in the range of 0.5 to 1.5 percent. The monies collected from the surcharge are used to underwrite DSM programs.

Shared savings programs are a form of revenue decoupling that break the linkage between profits and sales by rewarding a utility with a portion of the consumer surplus generated by the implementation of cost effective DSM. The utility has the opportunity through the design of the reward structure to increase profits by an amount greater than the cost of the lost sales. Typically the shared savings are 10-30% of the cost savings. In addition, all costs of implementing the DSM programs are recovered[17].

Performance-based ratemaking (PBR) is another mechanism to decrease the linkages between a utility's cost of service and its prices. The typical incentives that result from PBR can be categorized as sliding scale, price cap, and revenue cap. Under sliding scale regulation, prices are adjusted to keep a utility's rate of return within a pre-specified band. Price caps set a ceiling on the prices for utility services but may be indexed to increase with an appropriate rate of inflation, such as the consumer price index. Revenue caps are ceilings that are usually applied only to revenues from base rates. Some revenue caps are increased as the number of customers increase.[18]

According to the Institute for Energy Efficiency, as of March 2010, 13 states have enacted revenue decoupling and actions to decouple revenue are pending in 6 states. Seven states have lost revenue recovery mechanisms with action to institute a lost revenue recovery mechanism pending in one state. Performance incentives have been enacted in 21 states and are pending in 6 more. Fourteen states have a tariff rider/surcharge and 16 states have enacted a system benefits charge.[19] Recovery mechanisms by state are shown in Figure 2-3.

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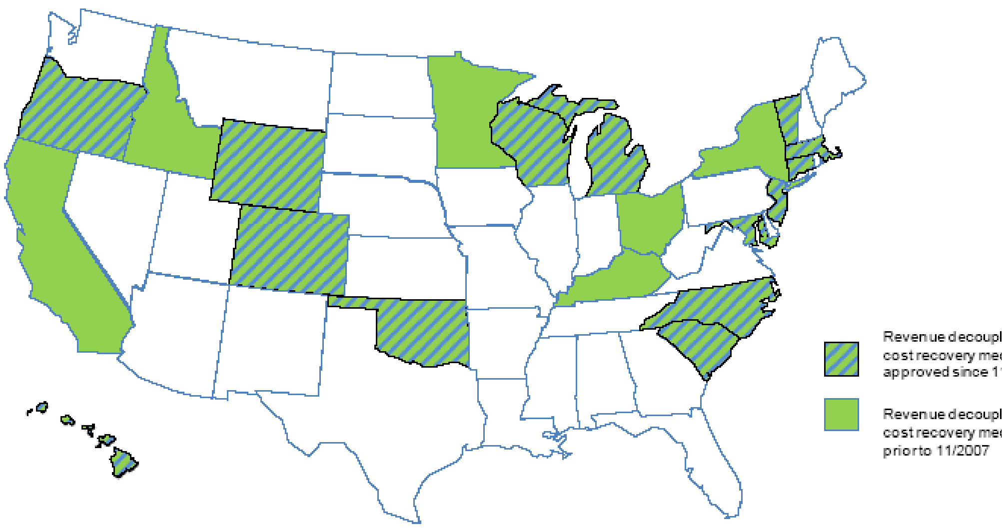
[16] "New Funding Source: IPUC Approves 0.5 Percent Rate Surcharge for Idaho Power DSM," www.newsdata.com/enernet/conweb/conweb77.html. "2000/10/25 – UE-001457 – PacifiCorp, d/b/a Pacific Power & Light – Tariff Revision," Docket: UE-001457, Washington Utilities and Transportation Commission, from www.wutc.wa.gov/webdocs.nsf.

[17] "Demand-Side Management of Electricity," www.colby.edu/personal/t/thtieten/dsm-ne.html.

[18] G.A. Comnes, A. Stoft, N. Greene, and L.J. Hill, *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues*, Volume I, Lawrence Berkeley National Laboratory, LBL-37577, UC-1320, November 1995.

[19] "Changes in State Regulatory Frameworks for Utility Administered Energy Efficiency Programs: November 2007-April 2010", Institute for Electric Efficiency, The Edison Foundation, http://www.edisonfoundation.net/iee/issueBriefs/index.htm.

Figure 2-3
Approved Energy Efficiency Fixed-Cost Recovery Mechanisms by State for Investor-Owned Utilities: 2007-2010[20]



In 2009, Senate Bill (SB) 376 was enacted in Missouri to create the Missouri Energy Efficiency Investment Act. Through the Act, the MPSC was directed to develop rules implementing the Act the primary tenets of which are:

- Electric companies must be allowed to implement and recover costs related to MPSC-approved energy efficiency programs.
- MPSC may develop cost recovery methods to encourage further investments in energy efficiency programs that can include:
    - Capitalization of investments
    - Rate design modifications
    - Accelerated depreciation
    - Retention of a portion of net benefits for the company's shareholders
- MPSC shall fairly apportion costs and benefits to each customer class, although costs to low-income customers can be reduced or exempted.

The MPSC rulemaking in this area is currently ongoing.

2.7 State of the Industry and this IRP

Empire's 2010 IRP considers a twenty-year planning horizon. Today, with all of the uncertainties discussed above, the resource planning process is a difficult and complex

[20] http://www.edisonfoundation.net/iee/issueBriefs/index.htm. "Changes in State Regulatory Frameworks for Utility Administered Energy Efficiency Programs," November 2007-April 2010, Institute for Electric Efficiency.

task. The IRP process, while rigorous, is built on a large set of planning assumptions that are always shifting. The plan is subject to the ongoing need to reevaluate modeling assumptions based on changing business conditions. The plans presented in this IRP are based on the best information available at the time that the analysis was conducted. It is a plan. Requests for proposals, further analysis, and, in some instances, regulator support are needed to turn aspects of the plan into actual projects.

Abbreviations

APPA – American Public Power Association
AQCS – Air Quality Control Systems
BACT – Best Available Control Technology
C&I – Commercial and Industrial
CAC – Central air conditioning
CAES – Compressed Air Energy Storage
CAIR – Clean Air Interstate Rule
CATR – Clean Air Transport Rule
CC – Combined cycle
CCR – Coal Combustion Residuals
CCS – Carbon capture and sequestration
CEM – Capacity Expansion Model
CHP – Combined heat and power
CO_2 – Carbon dioxide
CPC – Customer Programs Collaborative
CT – Combustion turbine
DG – Distributed generation
DSM – Demand-side Management
EEPS – Energy Efficiency Portfolio Standard
EERS – Energy Efficiency Resource Standard
EM&V – Evaluation, measurement and verification
EPA – Environmental Protection Agency
FERC – Federal Energy Regulatory Commission
HAPS – Hazardous Air Pollutants
Hg – Mercury
IEE – Institute for Energy Efficiency
IGCC – Integrated Gasification Combined Cycle
IRP – Integrated Resource Plan or integrated resource planning
KCC – Kansas Corporation Commission
kW – kilowatt
kWh – kilowatthour
MCSP – Missouri Carbon Sequestration Project
MPSC – Missouri Public Service Commission
MW – Megawatt
MWh – Megawatthour
NO_2 – Nitrogen dioxide
NRC – U.S. Nuclear Regulatory Commission
NSI – Net system input
PBR – Performance-based ratemaking
PHEV – Plug-in hybrid electric vehicle
$PM_{2.5}$ – Particular matter, 2.5 micrometers
PPA – Power purchase agreement
PVRR – Present Value of Revenue Requirements
PV – Photovoltaics

RAS – Resource Acquisition Strategy
RFP – Request for Proposals
RIM – Ratepayer Impact Measure
RPS – Renewable Portfolio Standard
SB – Senate Bill
SCR – Selective Catalytic Reduction
SMR – Small modular reactor
SO_2 – Sulfur dioxide
SPP – Southwest Power Pool

Appendix A
IRP Team Members

Senior Management

Brad Beecher, Executive Vice President and COO – Electric
Greg Knapp, Vice President – Finance and CFO
Kelly Walters, Vice President – Regulatory and General Services
Harold Colgin, Vice President – Energy Supply

Team Members

Todd Tarter, Manager of Strategic Planning (IRP Project Manager)
Scott Keith, Director Planning & Regulatory
Aaron Doll, Planning Analyst
Sherry McCormack, Energy Efficiency Coordinator
Blake Mertens, Director Strategic Projects, Safety and Environmental
George Thullesen, Director Environmental Policy
Tim Wilson, Renewables and Strategic Initiatives Manager
Rick McCord, Director of Supply Management
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Ventyx (modeling) – Diane Crockett
Technically Speaking (industry knowledge, report writing) – Jill Tietjen