MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

THE EMPIRE DISTRICT ELECTRIC COMPANY

ELECTRIC UTILITY RESOURCE PLANNING
TRIENNIAL COMPLIANCE FILING

FILE NO. EO-2016-0223

August 29, 2016

JEFFERSON CITY, MISSOURI

**** Denotes Highly Confidential Information ****

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THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NO. EO-2016-0223

EXECUTIVE SUMMARY

On April 1, 2016, The Empire District Electric Company ("Empire" or "Company") filed its 2016 Integrated Resource Plan ("IRP") triennial compliance filing ("Filing") in File No. EO-2016-0223. The Filing is Empire's second triennial compliance filing under the Commission's revised Chapter 22 Electric Utility Resource Planning Rules.[1] Following is a chronology of Empire's Chapter 22 triennial compliance filings and annual update filings[2] in the last ten (10) years:

Date Filed	Docket Number	Type of Filing
9/5/2007	EO-2008-0069	Triennial Compliance
9/3/2010	EO-2011-0066	Triennial Compliance
3/15/2012	EO-2012-0294	Annual Update
7/1/2013	EO-2013-0547	Triennial Compliance
3/11/2014	EO-2014-0243	Annual Update
3/13/2015	EO-2015-0216	Annual Update
3/1/2016	EO-2016-0223	Triennial Compliance

On April 1, 2015, Empire filed an Application for Variance in File No. EE-2015-0249 seeking variances from portions of 4 CSR 240-3.164 Demand-Side Programs Filing and Submission Requirements, 4 CSR 240-22.030 Load Analysis and Load Forecasting, and 4 CSR 240-22.050 Demand-Side Resource Analysis. The Commission issued an Order Granting Application for Variance on June 2, 2015.

On October 28, 2015, the Commission issued an order in File No. EO-2016-0040 and established eleven (11) special contemporary planning issues for Empire to analyze and document in its 2016 triennial Integrated Resource Plan. Empire's responses to these special contemporary issues can be found in IRP Volume 6.

Volume 1 of the IRP is Empire's 45-page Executive Summary of the IRP.

For its Executive Summary in this Report, Staff provides the following bullet points to further summarize the IRP:

[1] The Commission's original Chapter 22 Rules were first effective on May 6, 1993, and remained unchanged until they were revised on June 30, 2011.
[2] Annual update filings requirements became effective on June 30, 2011 as a result of the effective date for revised Chapter 22 rules.

- Forecasted 20-year base case load forecasts for retail MWh energy sales and MW summer peak demand which have compound annual growth rates of ** _____ ** and ** _____ **, respectively, and continue the dramatic downward trend in Empire's historic and forecasted load growth;[3]
- Nineteen (19) alternative resource plans: five (5) base plans (including Plan 2 realistic achievable potential ("RAP")[4] demand-side management resources ("DSM"), Plan 3 RAP+ DSM, Plan 4 RAP- DSM, and Plan 5 No DSM), three (3) required plans[5] and eleven (11) contingency plans;[6]
- Key inputs to and the process for integrated resource analysis of each alternative resource plan for 20-year and 40-year planning horizons including analysis of the following critical uncertain factors: natural gas prices, cost of carbon dioxide ("CO_2") regulations, load growth, and cost of capital/debt;
- Outputs of the integrated resource analysis including a capacity balance sheet and the following "risk adjusted"[7] annual performance metrics for each alternative resource plan: revenue requirements, present value of revenue requirements ("PVRR"), average retail rates, average % rate change in retail rates, pre-tax interest coverage, total debt to capital ratio, and net cash flow to capital expenditure;
- Empire's decision-makers[8] selected Plan 5 No DSM as Empire's adopted preferred resource plan based on Plan 5 having the lowest PVRR[9] and identified Plan 10 Low Load as a contingency plan under the No CO_2 and Low Load scenario and under the No CO_2 and High Market/Gas Prices scenario; and
- Empire's 2016 – 2019 implementation plan includes no demand-side resources and no changes to the Company's existing supply-side resources.

[3] IRP, Volume 3, Figure 3-18 and Figure 3-19 contain comparisons of net system input MWh and MW, respectively, for actual historical (beginning with 1990) and base case load forecasts from the 2007, 2010, 2013, and 2016 IRPs.
[4] 4 CSR 240-22.020(49) defines realistic achievable potential.
[5] 4 CSR 240-22.060(3)(A) includes requirements for defining alternative resource plans.
[6] IRP, Volume 6, pages 26 – 28 includes a description of each of the 19 alternative resource plans.
[7] IRP, Volume 6, pages 138 - 139.
[8] IRP, Volume 7, page 19.
[9] IRP, Volume 7, page 7: Empire looked at the difference in the 20-year PVRR among these base plans as well as the 40-year PVRR basis to aid in its selection of the preferred plan. Plans 2, 3 and 4 are all very close with regard to PVRR, but Plan 5 has a lower PVRR. Therefore, considering all of the preferred plan selection criteria, and attempting to strike a balance over all of the planning objectives, Empire has selected the lowest cost base plan, Plan 5, the No DSM Scenario, as the preferred plan.

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Plan 5 No DSM has the following Highly Confidential capacity balance sheet, which has approximately ** ____

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As a result of its review of the IRP's filed documents and work papers, Staff has identified ten (10) deficiencies[10] and three (3) concerns[11] which are discussed in more detail in later sections of this Report.

The most significant deficiencies identified by Staff are related to Empire's failure to include estimates of the following costs in its analysis of alternative resources plans with demand-side resources: 1) utility financial incentives or lost earnings opportunities as a direct result of DSM programs, 2) cost to own and operate DSM data management and tracking software, and 3) cost to own and operate DSM benefit/cost analysis software.

Deficiency 10 - Empire did not include any cost of utility financial incentives or lost earning opportunity in its alternative resource plans which have DSM resources as required by 4 CSR 240-22.060(4)(C).

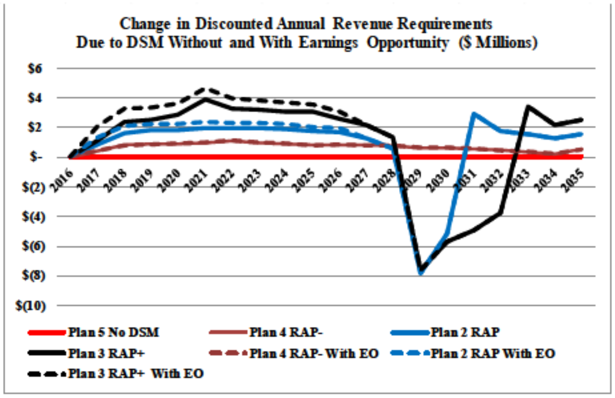
4 CSR 240-22.060(4)(C) requires that Empire provide analysis of economic impact of utility financial incentives or lost earnings opportunity as a direct result of demand-side resources upon: 1) estimated annual revenue requirements, 2) estimated annual average rates, 3) percentage increase in the average rate from the prior year, and 4) estimated company financial ratios and credit metrics. Empire did not include any utility financial incentive costs or lost earnings opportunity in any of its alternative resource plans.[12] Staff's analysis of the change in annual revenue requirements resulting from Empire's lost earnings opportunities for the Plan 2 RAP DSM, Plan 3 RAP+ and Plan 4 RAP- is summarized in the following charts:

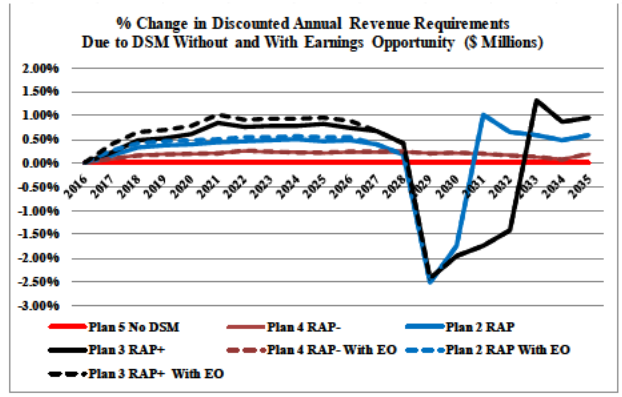
continued on next page

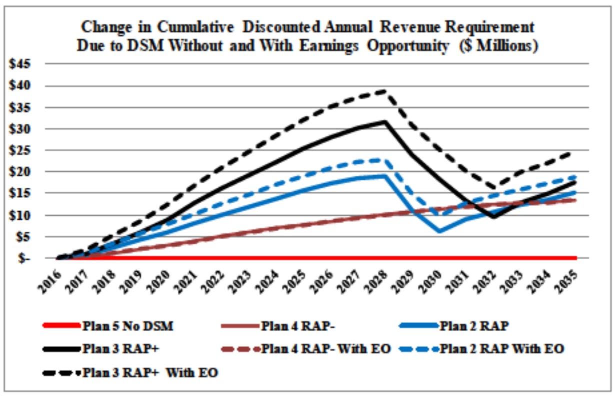
[10] A "deficiency" is defined in Rule 4 CSR 240-22.020(9) as "deficiencies in the electric utility's compliance with the provisions of [Chapter 22], any major deficiencies in the methodologies or analyses required to be performed by [Chapter 22], and anything that would cause the electric utility's resource acquisition strategy to fail to meet the requirements identified in Chapter 22."

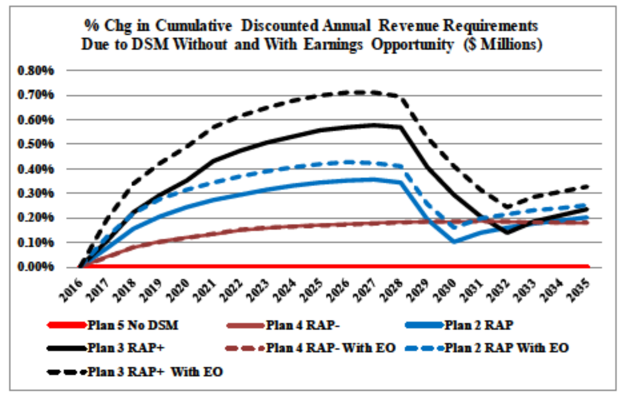
[11] A "concern" is defined in Rule 4 CSR 240-22.020(6) as "concerns with the electric utility's compliance with the provisions of [Chapter 22], any major concerns with the methodologies or analyses required to be performed by [Chapter 22], and anything that, while not rising to the level of a deficiency, may prevent the electric utility's resource acquisition strategy from effectively fulfilling the objectives of Chapter 22."

[12] IRP, Volume 6, page 122.









Plan 5 No DSM and Plan 4 RAP- DSM both require installation of 100 MW Combined Cycle Turbine in 2029
Plan 2 RAP DSM requires installation of 100 MW Combined Cycle Turbine in 2031
Plan 3 RAP+ DSM requires installation of 100 MW Combined Cycle Turbine in 2033

Staff estimates that compliance with Rule 4 CSR 240-22.060(4)(C) would add approximately $3.4 million to the PVRR of Plan 2 RAP DSM and approximately $6.5 million to the PVRR of Plan 3 RAP+ DSM:

	PVRR (Millions of 2016 Dollars)			
	Plan 5 No DSM	Plan 4 RAP -	Plan 2 RAP	Plan 3 RAP +
Without Earnings Opportunity ("EO")	$ 7,511.6	$ 7,525.1	$ 7,526.7	$ 7,529.2
$ Increase Over Plan 5 Without EO	$ -	$ 13.5	$ 15.1	$ 17.6
% Increase Over Plan 5 Without EO	n/a	0.18%	0.20%	0.23%
Staff Estimate of Lost EO (1)	$ -	$ -	$ 3.4	$ 6.5
With Earnings Opportunity (EO)	$ 7,511.6	$ 7,525.1	$ 7,530.2	$ 7,535.7
$ Increase Over Plan 5 With EO	$ -	$ 13.5	$ 18.6	$ 24.1
% Increase Over Plan 5 With EO	n/a	0.18%	0.25%	0.32%

(1) PVRR of annual pre-tax lost earnings opportunity over the 50-year life of 100 MW combined cycle generator installed in 2029, 2031 and 2033 for Plans 4 and 5, Plan 2, and Plan 3, respectively.

Significant results of Staff's analysis of Empire's earning opportunities for alternative resource plans with demand-side resources include:

- Increases in the 20-year PVRR for Plan 2 RAP DSM and Plan 3 RAP+ DSM (both with earning opportunities included) relative to Plan 5 No DSM are estimated to be $18.6 million and $24.1 million, respectively; and
- Increases in discounted cumulative annual revenue requirements for Plan 2 RAP DSM and Plan 3 RAP+ DSM (both with earning opportunities included) relative to Plan 5 No DSM are estimated to be $23 million and $39 million, respectively, in 2028 - just prior to the 2029 installation of the 100 MW combined cycle turbine generator in Plan 5 No DSM.

To resolve this deficiency, Empire should analyze the economic impact of alternative resource plans, calculated with and without utility financial incentives or lost earnings opportunities for demand-side resources, and comparative estimates for each year of the planning horizon as required by 4 CSR 240-22.060(4)(C) within its 2019 triennial compliance filing.

Deficiency 3 - Empire did not provide any costs for operating licenses and for administration related to 1) DSM data management and tracking software system, and 2) DSM benefit/cost analysis software system for its alternative resources plans with demand-side resources as required by 4 CSR 240-22.050(3)(G)5.D.

Staff has not estimated the annual costs for Empire to remedy this deficiency, but Staff believes these costs to be "six figures" amounts annually based upon Staff's experience gained while completing prudence reviews[13] for other electric utilities.

To resolve this deficiency, Empire should evaluate the cost to the customer and to the utility of technology to implement a potential demand-side program required by 4 CSR 240-22.050(3)(G)5.D – including all costs related to software systems to 1) track all costs and energy and demand savings and 2) calculate the cost-effectiveness of the DSM programs - in its 2019 triennial compliance filing.

Staff Expert Witness: John Rogers

[13] File Nos. EO-2015-0029 and EO-2015-0180.

4 CSR 240-22.010 POLICY OBJECTIVES

Linkage between Chapter 22 Rules, the MEEIA and MEEIA Rules

Staff performed its review of the Filing in the context of the Commission's Chapter 22 Rules,[14] the Missouri Energy Efficiency Act of 2009[15] ("MEEIA"), and the Commission's MEEIA Rules.[16] Staff performed its review in this way because the policy objectives of Chapter 22 and of MEEIA are inseparable for electric utilities, since Rule 4 CSR 240-22.010(2) states:

> The fundamental objective of the resource planning process at electric utilities *shall* be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and *in a manner that serves the public interest and is consistent with state energy and environmental policies.* …
> (Emphasis added)

MEEIA establishes the following state energy policy for valuing demand-side resources and supply-side resources and for the cost recovery of these resources for Missouri's electrical corporations[17] in Section 393.1075.3 and .4:

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy, the commission shall:
> (1) Provide timely cost recovery for utilities;
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.
>
> 4. The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings.

Although electric utilities are not required to request Commission approval of demand-side programs and a demand-side programs investment mechanism ("DSIM") under MEEIA and the Commission's MEEIA rules, electric utilities are required to comply with the Commission's

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[14] 4 CSR 240-22 Electric Utility Resource Planning.
[15] 393.1075, RSMo, Supp. 2015.
[16] 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094.
[17] 4 CSR 240-22.020(16): "Electric utility or utility mean any electrical corporation as defined in section 386.020, RSMo, which is subject to the jurisdiction of the commission."

Chapter 22 Rules which establish that the fundamental objective of the electric utility resource planning process at each electric utility shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. Because MEEIA establishes state energy policy, each electric utility is required – as part of its electric utility resource planning –- to develop candidate resource plans and to analyze and document DSIMs which can allow the electric utility to make reasonable progress toward a goal of all cost-effective demand-side savings.[18]

It is important to also note the linkages between Chapter 22 Rules and the MEEIA Rules included in Rule 4 CSR 240-20.094(3)(A):

> (A) For demand-side programs and program plans that have a total resource cost test ratio greater than one (1), the commission shall approve demand-side programs or program plans, and annual demand and energy savings targets for each demand-side program it approves, provided it finds that the utility has met the filing and submission requirements of 4 CSR 240-3.164(2) and the demand-side programs and program plans-
> 1. Are consistent with a goal of achieving all cost-effective demand-side savings;
> 2. Have reliable evaluation, measurement, and verification plans; and
> 3. Are included in the electric utility's preferred plan or have been analyzed through the integration process required by 4 CSR 240-22.060 to determine the impact of the demand-side programs and program plans on the net present value of revenue requirements of the electric utility.

Of less significance – but still important – is the linkage between Chapter 22 Rules and the MEEIA Rules in Rule 4 CSR 240-22.070(8):

> Evaluation of Demand-Side Programs and Demand-Side Rates. The utility shall describe and document its evaluation plans for all demand-side programs and demand-side rates that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). Evaluation plans required by this section are for planning purposes and are separate and distinct from the evaluation, measurement, and verification reports required by 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7); nonetheless, the evaluation plan should, in addition to the requirements of this section, include the proposed evaluation schedule and the proposed approach to achieving the evaluation goals pursuant to 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7). The evaluation plans for each program and rate shall be developed before the program or rate is implemented and shall be filed when the utility files for approval of demand-side programs or demand-side program plans with the tariff application for the program or rate as described in 4 CSR 240-20.094(3).

[18] 4 CSR 240-20.094(2) "Guideline to Review Progress Toward an Expectation that the Electric Utility's Demand-Side Programs Can Achieve a Goal of All Cost-Effective Demand-Side Savings."

Finally, the MEEIA rules provide – in 4 CSR 240-3.164(2)(A) – detailed requirements for conducting current market potential studies including requirements for: 1) use of primary research, 2) updating the potential study no less frequently than every four (4) years, 3) review by Staff and stakeholders of required documentation, and 4) identification and discussion of the twenty (20)-year baseline energy and demand forecasts. Chapter 22 includes specific requirements for demand-side management potential studies in 4 CSR240-22.050(2), demand-side programs potential in 4 CSR 240-22.050(3), and demand-side rates potential in 4 CSR 240-22.050(4).

Staff Expert Witness: John Rogers and Brad Fortson

4 CSR 240-22.030 LOAD ANALYSIS AND LOAD FORECASTING

Summary

4 CSR 240-22.030, Load Analysis and Forecasting, has a stated purpose of setting the "minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing loads, and the purposes to be accomplished by load analysis and by load forecast models. The load analysis for this rule is intended to support both demand-side management efforts of 4 CSR 240-22.050 and the load forecast models of this rule. This rule also sets the minimum standards for the documentation of the inputs, components, and methods used to derive the load forecasts."

The Load Analysis and Load Forecasting Rule allows the utility to use multiple analytical methods for performing its load analysis and develop its forecasts, leaving it to the utility's discretion to choose the methods by which it achieves the stated purpose of the rule.

Empire requested waivers from specific provisions of this rule. All were granted by the Commission. These waivers pertained to all or part of the following subsections of the rule:

4 CSR 240-22.020 (37)	Major class is cost-of-service class of the utility
4 CSR 240-22.030(7)(A)	Major Class and Total Load Detail
4 CSR 240-22.030 (4)(A)(1)	Analysis of Use Per Unit. End-Use Load Detail.

Over the past 10 years, Empire has filed IRP forecasts in 2007, 2010, 2013, and 2016. Beginning with the 2013 IRP filing, Empire began using statistically adjusted end-use (SAE) models and a new economic vendor. As a result, there is no direct comparison of independent variables and forecasting models from 2007 and 2010 with the 2013 and 2016 independent variables and forecasting models. The 2013 and 2016 IRPs are similar, in that both use statistically adjusted end-use (SAE) models. However in the 2013 IRP, economic variables were based on state-level economic forecasts, and in the 2016 IRP, economic variables are based on the Joplin and Springfield Metropolitan Statistical Areas.

A comparison of historical energy net system input (MWh) and system peak (MW) to the base case forecasts in 2007, 2010, 2013, and 2016 IRPs are shown in the following figures.[19,20]

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[19] IRP, Vol. 3, page 70
[20] IRP, Vol. 3, page 72

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These figures show that actual historical energy system input and system peak ** _____

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________________________________ **

For the planning forecast period of 2016 to 2035, Empire's retail energy sales are forecasted to grow at a compound annual rate of about ** _____ ** for overall growth in retail energy sales of about ** _____ **. Retail peak demand is forecasted to grow at a compound annual rate of about ** _____ ** for an overall growth in retail peak demand of about ** _____ **.

In Staff's review of Empire's load analysis and energy and demand forecasts, Staff found no deficiencies concerning compliance with this rule and Staff has not identified any additional concerns. In Staff's opinion, the Integrated Resource Analysis filing meets the Load Analysis and Load Forecasting requirements of 4 CSR 240-22.030.

Staff Expert Witness: David Roos

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4 CSR 240-22.040 SUPPLY SIDE RESOURCE ANALYSIS

Summary

Rule 4 CSR 240-22.040 Supply-Side Resource Analysis requires Empire to review existing resources for opportunities to upgrade or retire existing resources and also review a wide variety of supply-side resource options to determine cost estimates for each type of resource.

Resource options are to be ranked based upon their relative levelized annual costs,[21] including installed capital costs, fixed and variable operation and maintenance costs, and probable environmental costs levelized over the useful life of the potential supply-side resource option using the utility discount rate.[22] Resources which do not have significant disadvantages pass this pre-screening process and are to be included in the integrated resource analysis process used to select a preferred resource plan.

Empire selected the following potential supply-side resource options for further investigation:[23]

1. Super-critical coal (with carbon capture and sequestration ("CCS"))
2. Simple cycle combustion turbine ("CT") (Aero-derivative CT, E-class frame CT, F-class frame CT)
3. Combined cycle ("CC") (unfired and fired)
4. Reciprocating engines
5. Small modular nuclear reactor
6. Distributed generation including microturbine and combined heat and power ("CHP")
7. Integrated gasification combined cycle (with CCS)
8. Traditional nuclear
9. Wind
10. Biomass (poultry waste)
11. Landfill gas (reciprocating engine)
12. Utility scale solar photovoltaic
13. Battery storage

[21] 4 CSR 240-22.020(29) Levelized cost means the dollar amount of a fixed annual payment for which a stream of those payments over a specified period of time is equal to a specified present value based on a specified rate of interest.
[22] 4 CSR 240-22.040(2)(A).
[23] IRP, Volume 4, page19.

Each of the above options was screened assuming 100 percent ownership by Empire. While partial ownership or a PPA might offer advantages over full ownership, screening each option in this manner allows for a direct comparison of the different technologies. [24]

Empire developed assumptions associated with the candidate resources, such as capital costs, fuel and purchased power costs, probable environmental costs, fixed and variable operations and maintenance ("O&M") costs, transmission and distribution ("T&D") costs and other operational data.[25]

Empire developed screening curves, but did not eliminate any candidate resources from consideration based on capacity expansion modeling ("CEM"). Therefore, all supply-side candidates were passed on to the integration analysis phase of the IRP process for consideration.[26] Empire calculated implementation and busbar costs for each of the potential supply-side resource options listed in the IRP's Table 4-4 (conventional technologies) and Table 4-5 (renewable and storage technologies). The IRP's Figures 4-4 through 4-7 depict the levelized busbar costs of the potential supply-side resource options under the "base environmental" cost scenario compared to varying capacity factors.[27]

Empire evaluated probable environmental compliance costs of supply side resource options and identified the following newly proposed and developing environmental regulations that could impact resource planning:[28]

1. Mercury Air Toxic Standards ("MATS") rule;
2. Cross State Air Pollution Rule ("CSAPR")/Clean Air Interstate Rule ("CAIR");
3. Cooling water intake structure issues (Clean Water Act Section 316(b));
4. Federal Resource Conservation and Recovery Act ("RCRA") governing the management and storage of coal combustion residuals ("CCR"), often referred to as coal ash;
5. Greenhouse gas ("GHG") legislation/regulations (e.g. The Clean Power Plan ("CPP"))
6. Effluent Limit Guidelines ("ELG");
7. SO_2, NO_2, ozone, PM National Air Quality Standards ("NAAQS"); and
8. Clean Water Act Section 316(a).

[24] Ibid.
[25] IRP Volume 1, page 19.
[26] Ibid.
[27] IRP Volume 4, pages 20 – 25.
[28] IRP Volume 4, page 26.

Empire is currently in material compliance with MATS, although the regulations have been remanded to the D.C. Circuit Court for further consideration.[29] MATS remains in effect until the D.C. Circuit Court acts. Accordingly, Empire and other entities subject to MATS must comply with its terms absent further relief granted.[30]

Under the CSAPR Program, in Empire's most current five-year business plan, which assumes normal operation while maintaining compliance with permit conditions, Empire anticipates it will continue to assess the allowance market to determine if it is economically beneficial to purchase allowances for some of the pollutants.,

Empire examined recent and possible upgrades at its existing plants, and identified the following recent and possible upgrades[31]:

1. New pollution control systems are installed at the Iatan 1 unit. A scrubber, SCR, fabric filter, and powder activated carbon system were installed at the jointly owned Iatan Unit 1 coal-fired unit in 2009;
2. New pollution control systems are installed at the Asbury 1 unit. Unit 1 is retrofitted with an SCR, scrubber, fabric filter, and a powder-activated carbon injection system. This AQCS project and steam turbine project was completed in 2015. Unit 2 was retired in 2013;
3. The conversion of Riverton 12 (a CT) to a CC unit was completed in mid-2016; and
4. Empire's normal, ongoing maintenance program at each of its plants addresses critical operational and mechanical issues to ensure the longevity of the units.

Empire evaluated interconnection and transmission requirements associated with the preliminary supply-side options and assigned a cost of $62.98/KW in 2016 dollars for each candidate resource.[32] Empire determined the 2015 respective avoided transmission cost by averaging the SPP Aggregate Facility Study ("AFS") Engineering and Construction ("E&C") costs compared to the requested MW resources from 2008 to 2014.[33] The cost is then extrapolated for future years by escalating 2.5 percent per year.[34] Empire is a member of the SPP and relies on SPP to determinate which transmission lines will be built by members of SPP, when the lines will be built, and the cost allocation to members of SPP for those lines. The SPP

[29] IRP Volume 4, page 27.
[30] IRP Volume 4, page 28.
[31] IRP Volume 4, pages 14 -15.
[32] IRP, Volume 4, page 45.
[33] IRP, Volume 4.5, Table 4.5-4, and page 37.
[34] IRP, Volume 4, page 44.

conducts studies directly associated with transmission planning and develops the transmission expansion plan ("STEP"). Since not all of Empire's planned construction projects are accounted for in the STEP, Empire provided details for its 2016 to 2020 construction budget in Appendix H to Volume 4.5 of its IRP.[35]

Empire did not identify any transmission system capacity constraints that would limit the output of the Riverton 12 CC conversion.[36]

As a member of the SPP, Empire is required to maintain a minimum 12% capacity margin which is approximately equivalent to a 13.7% reserve margin. This value was used as the minimum reserve margin value for capacity planning in this IRP.[37]

In 2015, 77% of Empire's total system input (in kWh) was supplied by its steam and thermal generation units, 1% was supplied by its hydroelectric generation, and the remaining 22% was purchased power including coal and wind energy. The 2015 Empire net system input by fuel type is shown in the following table.[38]

Power Plant Resource	**Fuel Type**	**State**	**Interest (%)**	**Capacity (MW)**	**Start Date**	**Facility Age (Years)**
Asbury 1	Coal	MO	100	194	1970	45
Iatan 1	Coal	MO	12	85	1980	35
Iatan 2	Coal	MO	12	105	2010	5
Plum Point	Coal	AR	7.52	50	2010	5
Riverton 10 CT[39]	Natural Gas	KS	100	16	1988	27
Riverton 11 CT	Natural Gas	KS	100	17	1988	27
Riverton 12 CT	Natural Gas	KS	100	250	2007	8
Empire Energy Center 1 CT	Natural Gas/Oil	MO	100	82	1978	37
Empire Energy Center 2 CT	Natural Gas/Oil	MO	100	82	1981	34
Empire Energy Center 3 CT	Natural Gas/Oil	MO	100	49	2003	12
Empire Energy Center 4 CT	Natural Gas/Oil	MO	100	49	2003	12
State Line CT	Natural Gas/Oil	MO	100	94	1995	20
State Line CC	Natural Gas	MO	60	297[40]	1997 & 2001[41]	18 & 14
Ozark Beach	Hydro	MO	100	16	1913	102
Total Empire Installed Capacity				1,386		
Long Term Power Purchases		**Type**		**Capacity (MW)**	**End Date**	**Term**
Plum Point		Coal		50	2040	30 years
Elk River Wind Farm[42] (150 MW PPA)		Wind		17	2025	20 years
Meridian Way Wind Farm (105 MW PPA)[43]		Wind		19	2028	20 years

[35] IRP, Volume 4, page 45.
[36] IRP, Volume 4, page 46.
[37] IRP, Volume 4, page 15.
[38] IRP, Volume 4, page 3.
[39] Riverton 10 and 11 were manufactured in 1967 but were installed at Empire in 1988; they are 43 years old.
[40] Represents Empire's 60 percent share of a 500 MW State Line Combined Cycle unit.
[41] One of the gas turbines at State Line Combined Cycle unit was installed in 1997 and is 18 years old. The other gas turbine and the steam turbine were installed in 2001.
[42] The Elk River Wind Farm consists of one-hundred (100) 1.5 MW turbines for a total of 150 MW. For purposes of the IRP, 17 MW of its installed capacity is counted toward Empire's reserve margin. The capacity is subject to rerating in the future. Although the term of the PPA is 20 years, the term can be extended once for a period of 5 years at Empire's option.

Capacity Summary				
Total Coal	Coal	434		
Total Gas Turbine	Gas	389		
Total Combined Cycle	Combined Cycle	547		
Total Hydro	Hydro	16		
Total Purchase includes wind	Purchased Power	86		
Total	All	1,472		

Supply Side Resources & The Missouri Renewable Energy Standard (RES)

Rule 4 CSR 240-22.040, Supply-Side Resource Analysis, requires Empire to review a wide variety of supply-side resource options, including a wide variety of renewable generation technologies and technologies for distributed generation. Empire included the following renewable technologies, which have the potential to be eligible for Missouri RES compliance, in its supply-side analysis:

1. Utility scale solar photovoltaic
2. Landfill gas (reciprocating engine)
3. Biomass (poultry waste)
4. Wind

Empire selected all of the listed renewable technologies as final candidate resource options to represent renewable options. In addition to the renewable technologies listed, Empire included battery storage in an alternative resource plan.

The Staff has identified one deficiency related to Empire's supply-side resource analysis.

Deficiency 1 - Empire did not estimate probable environmental costs of potential supply-side resource options as required by 4 CSR 240-22.040(2)(B).

Instead of estimating probable environmental costs of potential supply-side resources by estimating the cost of the utility to comply with additional environmental legal mandates and to specify a subjective probability of additional environmental legal mandates occurring during the planning horizon, Empire anticipated that all compliance costs would be recoverable in rates.

To resolve this deficiency, Empire should comply with the requirements of 4 CSR 240-22.040(2)(B) within its 2019 triennial compliance filing.

Staff Expert Witness: J Luebbert

[43] The Meridian Way Wind Farm began commercial operation on December 15, 2008. The facility is rated at 105 MW and approximately 19 MW is counted toward Empire's reserve margin. The capacity is subject to rerating in the future. The net capability is based on metered hourly net power output data, and Empire is required by SPP to recalculate the net capability at least every three years.

4 CSR 240-22.045 TRANSMISSION AND DISTRIBUTION ANALYSIS

Summary

Rule 4 CSR 240-22.045 Transmission and Distribution Analysis specifies minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting. Rule 4 CSR 240-22.045 does not prescribe how analyses are to be done, but rather allows a utility to conduct its own analysis or adopt the regional transmission operator ("RTO") or Independent Transmission System Operator ("ISO") transmission plans. Rule 4 CSR 240-22.045 requires analysis and documentation of the RTO/ISO transmission projects and requires the electric utility to review transmission and distribution for the reduction of power losses, interconnection of new generation facilities, facilitation of sales and purchases, and incorporation of advance technologies for the optimization of investment in transmission and distribution resources.

Empire did not request any variances from Rule 4 CSR 240-22.045 as a part of this Chapter 22 filing.

The Staff has identified one deficiency and one concern related to Empire's supply-side resource analysis.

Deficiency 2 - Empire did not provide cost benefit analyses of advanced grid technologies as required by 4 CSR-240-22.045(4)(E)1. and 2.

To resolve this deficiency, Empire should develop, describe, and document the utility's cost benefit analysis and implementation of advanced grid technologies and provide the information within its 2019 triennial compliance filing.

Concern A - Empire did not provide the costs of all identified advanced grid technologies as required by 4 CSR-240-22.045(4)(C)1.A.

Empire provided the costs of some advanced grid technologies required by 4 CSR-240-22.045(4)(C)1.A. However, Empire did not provide costs for the following advanced grid technologies:

- Transformer fiber optic winding temperature sensors
- Transformer comprehensive health monitoring
- Fiber optic substation data network
- Substation data archive, server, and database
- 69 kV vacuum circuit breaker

To remedy this concern, Empire should provide the costs of all advanced grid technologies within its 2019 triennial compliance filing.

Staff Expert Witness: J Luebbert

4 CSR 240-22.050 DEMAND-SIDE RESOURCE ANALYSIS

Summary

Rule 4 CSR 240-22.050, Demand-Side Resource Analysis, "specifies the principles by which potential demand-side resource options shall be developed and analyzed for cost-effectiveness, with the goal of achieving all cost-effective demand-side savings." The rule identifies the objectives to be achieved by the demand-side programs and portfolios, and gives each utility the option of developing demand-side programs or portfolios from the top down (starting with program designs and filling in the cost-effective measures) or from the bottom up (starting with screening a comprehensive menu of measures and ending with program designs). The rule clarifies the distinction between demand-side programs and demand-side rates. The rule includes the calculation of the Total Resource Cost ("TRC") test, which meets the requirement of the MEEIA. The rule requires documentation regarding how the potential demand-side resources were analyzed and screened to identify demand-side candidate resource options to advance to the integrated resource analysis.

Finally, Rule 4 CSR 240-22.050 requires the selection of demand-side candidate resource options that are passed on to integrated resource analysis in Rule 4 CSR 240-22.060 and assessment of their technical potentials, maximum achievable potentials ("MAP"), and realistic achievable potentials ("RAP").

Empire meets quarterly with its demand-side management ("DSM") advisory group.

Empire filed an application for variance, approved on July 2, 2015, for Rule 4 CSR 240-22.050(1)(E). Per the approved variance, Empire addressed technology improvements by assessing the effect of impact and incremental cost trends on measure cost-effectiveness over the planning horizon. Empire included the effects of known improved technologies, accounting for proposed and approved changes in federal equipment standards as well as ENERGY STAR® and The Consortium for Energy Efficiency ("CEE") efficiency requirements. Emerging technologies with unpredictable savings or barriers to market availability were not included.

Empire engaged Applied Energy Group ("AEG") to conduct a DSM market potential study for its service territory and to help with the demand-side resource analysis requirements of 4 CSR 240-22.050. AEG's highest priority data sources for this study were those that were specific to Empire. Those data sources include: (1) Empire customer data; (2) Empire load forecasts; (3) economic information; (4) Empire residential saturation survey; and (5) Empire DSM program data. AEG maintains several databases and modeling tools that it uses for Empire's DSM market potential study.[44] Those AEG data sources include: (1) AEG Energy Market Profiles; (2) AEG's Building Energy Simulation Tool ("BEST"); (3) AEG's EnergyShape™; (4) AEG's Database of Energy Efficiency Measures ("DEEM"); and (5) recent DSM market potential studies. Several sources of data were used to characterize the energy efficiency measures. AEG used secondary data from recent studies performed for the Midwest, supplemented by AEG data (as previously mentioned), and national, well-vetted regional data sources such as Appliance and Equipment Standards and numerous Technical Reference Manuals from Midwestern states. The main secondary data sources are: (1) Annual Energy Outlook; (2) American Community Survey; (3) local weather data; (4) Database for Energy Efficient Resources ("DEER"); and (5) other relevant regional sources.

AEG developed nine (9) program design scenarios to assess the optimal demand-side programs to propose for implementation. The recommended demand-side management programs for 2017-2019 include: (1) Residential Lighting; (2) Whole House Efficiency; (3) Residential Behavioral; (4) Low Income Whole House Efficiency; (5) Low Income Weatherization; and (6) Commercial & Industrial Rebate. Additional programs were added to the portfolio after 2019 as measures and programs become cost-effective. AEG considered five (5) energy efficiency portfolios based on cost-effective measures. Each of these portfolios was considered during the integration phase of Empire's IRP process to determine which DSM portfolio was the optimal decision based upon Empire's supply options. Those portfolios are: (1) RAP- Portfolio; (2) RAP Program Design Portfolio; (3) RAP+ Portfolio; (4) MAP Program Design Portfolio; and (5) Aggressive Capacity Portfolio.

[44] IRP, Volume 5, Appendix A.

There are four common types of demand-side rates:[45]

1. Time-of-Use: Customers pay a higher price during the designated peak period and lower prices during off-peak periods. The designated peak and off-peak periods are typically defined by the season, day and time of day. Requires interval meter;
2. Critical Peak Price. Customers pay higher peak period prices during the few days a year when wholesale prices are the highest and pay a discounted off-peak price for the remainder of the year. Requires interval meter;
3. Peak Time Rebate. Customers are paid for load reductions during a peak period. There is no rate discount during non-event hours. Requires smart meter and method for estimating customer's baseline usage; and
4. Real Time Pricing. Customers pay for energy at a rate that is linked to the hourly market price for electricity. Depending on their size, participants are typically made aware of the hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers —above one megawatt of load — face hour-ahead prices. Requires interval meter.

According to Empire, these demand-side rate options have similar demand savings impacts but the implementation costs can vary significantly. AEG focused only on the demand-side rate option with the lowest implementation cost, Critical Peak Pricing ("CPP").[46] Empire did not evaluate the other three demand-side rates, due to higher implementation costs. However, it is possible that one of the demand-side rates may have had more benefits which would make it more cost effective than the rate with the lowest implementation cost (CPP). The demand response programs were modeled to start in 2022 to give Empire time to roll out AMI meters to participating customers.[47]

Empire developed its avoided demand costs utilizing the same basic methodology as the previous triennial compliance plan (2013 IRP) but with different/updated inputs to its integrated resource analysis. The IRP avoided demand costs were developed with input from its IRP Stakeholder Advisory Group. The Avoided Demand Cost is comprised of values for generation, transmission, and distribution. Empire began with $10/kW as the avoided generation cost, and increased that to $20/kW by 2018 and then trended this to the levelized carrying cost of an

[45] IRP Volume 5, page 20.
[46] Ibid.
[47] Ibid.

installed simple-cycle combustion turbine by 2028, which is approximately the first year of capacity needs for Empire's projected summer peak based on the base case assumptions of this IRP. In 2029 and beyond, Empire continued to use the levelized carrying cost of a simple-cycle combustion turbine escalated at the rate of inflation. For the transmission cost component of the avoided demand cost, Empire used the levelized carrying cost of the estimated transmission cost to interconnect a simple-cycle combustion turbine. Using the same approach as the previous IRP, Empire determined that the avoided distribution costs for demand-side screening purposes for its system would be close to zero.[48]

As a result of its review, Staff has found seven (7) deficiencies and one (1) concern relating to Rule 4 CSR 240-22.050.

Deficiency 3 - Empire did not provide any costs for operating licenses and for administration related to 1) DSM data management and tracking software system, and 2) DSM benefit/cost analysis software system for its alternative resources plans with demand-side resources as required by 4 CSR 240-22.050(3)(G)5.D.

Rule 4 CSR 240-22.050(3)(G)5.D. states:

> (3) The utility shall develop potential demand-side programs that are designed to deliver an appropriate selection of end-use measures to each market segment. The utility shall describe and document its potential demand-side program planning and design process which shall include at least the following activities elements: …
>
> (G) Estimate the characteristics needed for the twenty (20)-year planning horizon to assess the cost effectiveness of each potential demand-side program, including: …
>
> 5. For each year of the planning horizon, an estimate of the costs, including: …
>
> D. The cost to the customer and to the utility of technology to implement a potential demand-side program;

In response to this rule, Empire provided *Table 48 Total Utility Administrative Costs per Program* and *Table 49 Total Customer Incremental Costs per Program* instead of the cost to the customer and to the utility of technology. To implement a potential demand-side program, Empire would need to potentially install, operate and maintain two new data management and tracking software systems, one to track the costs and energy and demand savings associated with the installed measures and one to calculate the cost-effectiveness of the programs. These data management and tracking systems would be an additional cost of technology, since Empire does

[48] IRP, Volume 5, page 106.

not currently have these software systems and did not include estimates of these software systems in its alternative resource plans which include DSM resources.

To resolve this deficiency, Empire should evaluate the cost to the customer and to the utility of technology to implement a potential demand-side program – including the costs of software systems to 1) track all costs and energy and demand savings and 2) calculate the cost-effectiveness of the programs - in its 2019 triennial compliance filing.

Deficiency 4 – The IRP did not describe and document whether demand-side rates of other utilities would be applicable for Empire taking into account factors such as similarity in electric prices and customer makeup as required by 4 CSR 240-22.050(4)(A). Empire did not review demand-side rates that have been implemented by other utilities within the state.

Rule 4 CSR 240-22.050(4)(A) states:

> (4) The utility shall develop potential demand-side rates designed for each market segment to reduce the net consumption of electricity or modify the timing of its use. The utility shall describe and document its demand-side rate planning and design process and shall include at least the following activities and elements:
> (A) Review demand-side rates that have been implemented by other utilities and identify whether similar demand-side rates would be applicable for the utility taking into account factors such as similarity in electric prices and customer makeup; …

As part of the DSM potential study, Empire did not review demand-side rates that have been implemented and/or piloted by other utilities. Information regarding demand response programs that are currently being implemented is publically available in case numbers EO-2015-0254 and EO-2015-0252. In addition, the IRP does not identify whether similar demand-side rates would be applicable for Empire taking into account factors such as similarity in electric prices and customer makeup.

To resolve this deficiency, Empire should review demand-side rates that have been implemented by other utilities and identify whether similar demand-side rates would be applicable for the utility taking into account factors such as similarity in electric prices and customer makeup as part of its 2019 triennial compliance filing.

Deficiency 5 – Empire did not provide an estimate of the incremental and cumulative demand reduction and energy savings due to potential demand-side rates as required by 4 CSR 240-22.050(4)(D)4.

Rule 4 CSR 240-22.050(4)(D)4. states:

> (4) The utility shall develop potential demand-side rates designed for each market segment to reduce the net consumption of electricity or modify the timing of its use. The utility shall describe and document its demand-side rate planning and design process and shall include at least the following activities and elements: …
>
> (D) Estimate the input data and other characteristics needed for the twenty (20)-year planning horizon to assess the cost effectiveness of each potential demand-side rate, including: …
>
> 4. For each year of the planning horizon, an estimate of the incremental and cumulative demand reduction and energy savings due to the potential demand-side rate;

Empire provided *Table 60 Realistic Achievable Potential Incremental Net Coincident Demand Savings (MW)* and *Table 61 Maximum Achievable Potential Incremental Net Coincident Demand* Savings *(MW)*, however, neither of the tables displayed any demand savings for any of the potential demand-side rates. Empire also indicated that there was no energy savings associated with the programs. In Empire's DSM potential study, AEG only evaluated the least-cost demand-side rate, CPP. To be compliant with this Rule, AEG should have evaluated each potential demand-side rate. Nonetheless, Table 60 and 61 should at least have incremental net coincident demand savings for CPP.

To resolve this deficiency, Empire should provide an estimate of the incremental and cumulative demand reduction and energy savings due to potential demand-side rates within its 2019 triennial compliance filing.

Deficiency 6 – Regarding potential demand-side rates, Empire did not assess 1) cost of incentives to customers, 2) cost of utility administration, 3) incremental and cumulative number of participants, load impacts, utility costs, and program participant costs as required by 4 CSR 240-22.050(4)(D)5.A., Rule 4 CSR 240-22.050(4)(D)5.C. and Rule 4 CSR 240-22.050(4)(E), respectively. Further, Empire did not describe and document how it performed the assessments - over the 20-year planning horizon - of the cost effectiveness of potential demand-side rates as required by 4 CSR 240-22.050 (4)(G).

Rules 4 CSR 240-22.050(4)(D)5.A., 4 CSR 240-22.050(4)(D)5.C., 4 CSR 240-22.050(4)(E); and 4 CSR 240-22.050 (4)(G) state:

> (4) The utility shall develop potential demand-side rates designed for each market segment to reduce the net consumption of electricity or modify the timing of its use. The utility shall describe and document its demand-side rate planning and design process and shall include at least the following activities and elements: …
>
> (D) Estimate the input data and other characteristics needed for the twenty (20)-year planning horizon to assess the cost effectiveness of each potential demand-side rate, including: …

> 5. For each year of the planning horizon, an estimate of the costs of each potential demand-side rate, including:
>
> A. The cost of incentives to customers to participate in the potential demand-side rate paid by the utility. The utility shall consider multiple levels of incentives to achieve customer participation in each potential demand-side rate, with corresponding adjustments to the maximum achievable potential and the realistic achievable potentials of that potential demand-side rate; …
>
> C. The utility's cost to administer the potential demand-side rate; …
>
> (E) A tabulation of the incremental and cumulative number of participants, load impacts, utility costs, and program participant costs in each year of the planning horizon for each potential demand-side program; …
>
> (G) The utility shall describe and document how it performed the assessments and developed the estimates pursuant to subsection (4)(D) and shall document its sources and quality of information.

Empire is not compliant with Rule 4 CSR 240-22.050(4)(D)5.A., Rule 4 CSR 240-22.050(4)(D)5.C., Rule 4 CSR 240-22.050(4)(E), and Rule 4 CSR 240-22.050(4)(G), collectively for the same reason. Empire's response to each of those respective Rules was, "The Critical Peak Pricing was found not to be cost-effective for any customer class. While the Inclining Block rate was cost-effective, significant rate-making needs to take place to put the rate into effect. Additionally, the savings associated with Inclining Block Rates is subjective; an average savings value was utilized for the analysis but zero savings could be seen with the implementation of such a rate. Empire's current capacity balance and load forecast do not necessitate or support taking potentially-costly measures to promote additional conservation at peak times." Empire states there are four (4) common types of demand-side rates: (1) Time-of-use; (2) Critical Peak Pricing; (3) Peak Time Rebate; and (4) Real Time Pricing. Empire continues by stating, "These demand-side rate options have similar demand savings impacts but the implementation costs can vary significantly. AEG focused on the demand-side rate option with the lowest implementation cost, Critical Peak Pricing ("CPP")."[49] Empire asserts that CPP was not found to be cost-effective at any time during the twenty (20)-year timeframe, and therefore the remaining three (3) demand-side rate options were not analyzed. The Rules listed above each ask for description and documentation for each potential demand-side rate. By only evaluating CPP and not the other three (3) potential demand-side rates, Empire is not compliant with those respective rules. Although the IRP stated that all four (4) potential demand-side rates have similar demand savings impacts, there was no documentation of that evaluation to verify that statement. Additionally, with the focus on the demand-side rate with the lowest

[49] IRP, Volume 5, page 100.

implementation cost, CPP, the remaining three (3) potential demand-side rate costs went unevaluated. Furthermore, without evaluation of each potential demand-side rate, an appropriate determination cannot be made as to the cost-effectiveness of each potential demand-side rate.

In its DSM Potential Study, AEG considered a residential Inclining Block Rate ("IBR"). IBR is considered a conservation rate that, unlike other demand response and rate based options, has low to zero (0) operation, maintenance, and incentive costs. It appears that Empire's reason for not evaluating this potential demand-side rate further was that, "introducing this rate option requires a significant amount of rate making and regulatory changes that cannot be captured within the modeling."[50] Empire does not elaborate on what "a significant amount of rate making and regulatory changes" is. Staff is aware there would be a great deal of rate design assumptions needed for further evaluation, but Staff is unaware of the regulatory changes that would be needed. Regardless, further evaluation is possible, and needed, in order to be compliant with the above mentioned Rules.

To resolve this deficiency Empire should comply with all of the requirements of 4 CSR 240-22.050(4)(D), (E), and (G) in its 2019 triennial compliance filing. Empire should include and evaluate IBR as a potential demand-side rate in its 2019 triennial compliance filing.

Deficiency 7 – Empire did not provide an estimate of the costs of each potential demand-side rate that includes the cost to the utility of technology to implement the potential demand-side rates as required by 4 CSR 240-22.050(4)(D)5.B.

Rule 4 CSR 240-22.050(4)(D)5.B. states:

> (4) The utility shall develop potential demand-side rates designed for each market segment to reduce the net consumption of electricity or modify the timing of its use. The utility shall describe and document its demand-side rate planning and design process and shall include at least the following activities and elements:
> …
> (D) Estimate the input data and other characteristics needed for the twenty (20)-year planning horizon to assess the cost effectiveness of each potential demand-side rate, including:
> 5. For each year of the planning horizon, an estimate of the costs of each potential demand-side rate, including:
> …
> B. The cost to the customer and to the utility of technology to implement the potential demand-side rate;

[50] Ibid.

Empire's response to this Rule stated, "AEG did not identify any costs to the customer for participating in a demand-side rate program." The cost to the utility of technology to implement the potential demand-side rate is absent.

To resolve this deficiency, Empire should provide an estimate of the costs of each potential demand side rate that includes the cost to the utility of technology to implement the potential demand-side rates within its 2019 triennial compliance filing.

Deficiency 8 – Empire did not provide the costs of each potential demand-side rate which should be calculated as the sum of all incremental costs that are due to the rate (including both utility and participant contributions) plus utility costs to administer, deliver, and evaluate each potential demand-side rate as required by 4 CSR-240-22.050(5)(B)2.

Rule 4 CSR-240-22.050(5)(B)2. states:

> (5) The utility shall describe and document its evaluation of the cost effectiveness of each potential demand-side program developed pursuant to section (3) and each potential demand-side rate developed pursuant to section (4). All costs and benefits shall be expressed in nominal dollars. …
>
> (B) The total resource cost test shall be used to evaluate the cost effectiveness of the potential demand-side programs and potential demand-side rates. In each year of the planning horizon- …
>
> 2. The costs of each potential demand-side rate shall be calculated as the sum of all incremental costs that are due to the rate (including both utility and participant contributions) plus utility costs to administer, deliver, and evaluate each potential demand-side program;

Empire is not compliant with Rule 4 CSR-240-22.050(5)(B)2 since the costs of each potential demand-side rate was not calculated. Program costs were not analyzed since Empire concluded the demand-side rate pilot programs were not cost-effective. There was no documentation of this claim. Still, the Rule requires an evaluation of the costs of each potential demand-side rate.

To resolve this deficiency, Empire should provide the costs of each potential demand-side rate which should be calculated as the sum of all incremental costs that are due to the rate (including both utility and participant contributions) plus utility costs to administer, deliver, and evaluate each potential demand-side rate within its 2019 triennial compliance filing.

Deficiency 9 – Empire is not compliant with Rule 4 CSR-240-22.050(5)(C)3 because its utility cost tests were not performed to include, but separately identify, the costs of any rate of return or utility incentive in its recovery of DSM program costs.

Rule 4 CSR-240-22.050(5)(C)3. States:

> (5) The utility shall describe and document its evaluation of the cost effectiveness of each potential demand-side program developed pursuant to section (3) and each potential demand-side rate developed pursuant to section (4). All costs and benefits shall be expressed in nominal dollars. …
>
> (C) The utility cost test shall also be performed for purposes of comparison. … In each year of the planning horizon- …
>
> 3. The costs shall include, but separately identify, the costs of any rate of return or incentive included in the utility's recovery of demand-side program costs.

To resolve this deficiency, Empire should include, but separately identify, the costs of any rate of return or utility incentive included in the utility's recovery of demand-side program costs within its 2019 triennial compliance filing.

Staff Expert Witnesses: Brad Fortson for Energy Efficiency and J Luebbert for Demand Response

4 CSR 240-22.060 INTEGRATED RESOURCE ANALYSIS

Summary

This rule requires the utility to design alternative resource plans to meet the planning objectives identified in Rule 4 CSR 240-22.010(2), and sets minimum standards for the scope and level of detail required in resource plan analysis and for the logically consistent and economically equivalent analysis of alternative resource plans. The utility is to identify the critical uncertain factors that affect the performance of alternative resource plans and establishes minimum standards for the methods used to assess the risks associated with these uncertainties.

The utility shall develop cases for analysis that maximize reliance on energy efficiency and renewable energy resources and then develop optimal cases. The rule requires the development of alternative resource plans based on normal conditions and also to assess the robustness of each plan under more extreme conditions (high and low cases). The rule requires inclusion of performance measures of present worth of utility revenue requirements, with and without any financial performance incentives the utility is planning to request. The rule also requires analysis of financial parameters and, if required, description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating and documentation of the methods, analyses, judgments, and data the utility chooses.

Empire did not request any variances to Rule 4 CSR 240-22.060 as a part of this Filing.

Empire, through its consultant, ABB, developed, considered, and analyzed the present worth of long-run utility costs for 19 alternative resource plans by calculating the PVRR for each plan.[51] The alternative resource plans are shown in the table below.[52]

Table 6-2 - Summary of Alternative Resource Plans					
Plan	**Plan Description**	**Plan Type**	**DSM Portfolio**	**RPS**	**Carbon Costs for DSM**
1	Base Scenario	Base Plan	RAP Portfolio	None	Weighted
2	Base Scenario With RPS	Base Plan	RAP Portfolio	15 to 20% by 2021	Weighted
3	RAP + DSM	Base Plan	RAP + DSM	15 to 20% by 2021	Weighted
4	RAP – DSM	Base Plan	RAP – DSM	15 to 20% by 2021	Weighted
5	No DSM	Base Plan	None	15 to 20% by 2021	N/A
6	Federal Renewable Incentives	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
7	High Environmental DSM	Other Contingency Plan	High Environmental	15 to 20% by 2021	High
8	Low Environmental DSM	Other Contingency Plan	Low Environmental	15 to 20% by 2021	Low
9	No Environmental DSM	Other Contingency Plan	No Environmental	15 to 20% by 2021	None
10	Low Load	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
11	High Load	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
12	High-High Load	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
13	Low Fuel	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
14	High Fuel	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
15	Aggressive Electric Vehicle	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
16	Early Asbury Retirement	Other Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
17	Highly Aggressive DSM	Required Plan	MAP Portfolio	15 to 20% by 2021	Weighted
18	Aggressive Capacity DSM	Required Plan	Aggressive Capacity Portfolio	15 to 20% by 2021	Weighted
19	Aggressive Renewable	Required Plan	None	Only renewables utilized	N/A
Notes: DSM – Demand-side Management MAP – Maximum Achievable Potential	RAP – Realistic Achievable Potential RPS – Renewable Portfolio Standard				

[51] IRP, Volume 6, page 3.
[52] IRP, Volume 6, page 8.

Plan 1 (Base Case) was originally created to be a low cost plan without forcing it to adhere to RES requirements. However, based on the planning assumptions and the capacity expansion model results, this plan complies with the RES requirement even without forcing the plan to do so. Therefore, Plan 1 and Plan 2 (Plan 2 is the base case *required* to meet the RES) are equivalent in this case. All other plans are designed to comply with the RES mandates. Base Plans 1 through 4 all consider some form of the realistically achievable potential including RAP, RAP + and RAP –. Plan 5 is the only base plan that does not have a demand-side portfolio.[53] The primary difference in the base plans is the level of DSM. Plans 6-16 are considered contingency plans. Plan 6 examines the potential impact, if any, of current renewable incentives being in place for the entire planning horizon. Due to environmental uncertainty, Plans 7-9 consider various levels of future carbon costs. Plans 10-12 test the potential impacts of higher or lower load growth. Similarly, Plans 13-14 test the impacts of higher or lower fuel and market prices. Plan 15 is a special case to examine a potential future with an aggressive penetration of electric vehicles over the next twenty years. And finally, Plan 16 is a special "what-if" case to determine the impact of an early retirement of the Asbury coal-fired unit for any reason, but particularly due to potential greenhouse gas regulations. For IRP purposes, Asbury is planned to be retired in 2035, but in the early retirement case (Plan 16) it is assumed to retire in 2022 when it is assumed that carbon compliance would begin (for planning purposes) in the environmental scenarios that assumed some level of carbon costs.[54] For the purposes of this IRP, all resource plans assume the retirement of Energy Center 1 in 2023, Energy Center 2 in 2026, Riverton 10 and 11 in 2033, and Asbury 1 in 2035.[55] Plan 19 (Aggressive Renewable) was developed to utilize only renewable energy resources for new generation including wind, landfill gas, solar, and biomass generation.[56] Plan 18 (Aggressive Capacity DSM) was developed using only DSM to meet future capacity needs, but also includes sufficient renewable resources for compliance with the RES (15 to 20 percent by 2021).[57]

The present worth of probable environmental costs were developed based upon the expected risk levels for implementation of CO_2 regulations on existing generation:[58]

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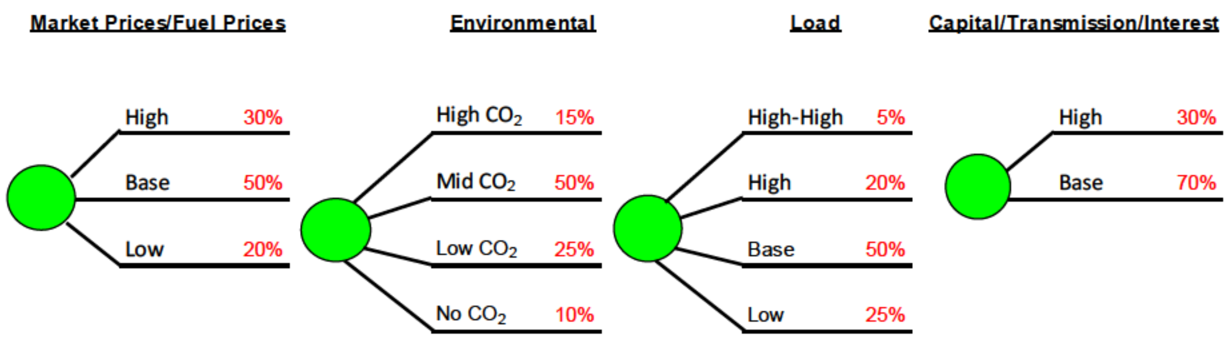
[53] IRP, Volume 6, page 9.
[54] IRP, Volume 6, page 12.
[55] IRP, Volume 6, page 13.
[56] IRP, Volume 6, page 10.
[57] Ibid.
[58] IRP, Volume 6, page 4.

- High: 15 percent CO_2 regulation by 2022;
- Moderate: 50 percent CO_2 regulation by 2022 (the base assumption);
- Low: 25 percent CO_2 regulation by 2022; and
- No: 10 percent no CO_2 regulations throughout the 20-year planning period.

Synapse CO_2 cost estimates were used for the projected CO_2 allowance prices in the three scenarios that considered carbon costs.[59]

All plans are modeled with Midas Gold and the Capacity Expansion Model® to determine their PVRR and other annual performance measures for the base case. This is referred to as deterministic runs.[60] The plans are then subjected to decision analysis and risk analysis by applying critical uncertain factors – through a decision tree analysis – of each plan. This is referred to as stochastic runs.[61] The following table shows the general description and subjective probabilities for Empire's critical uncertain factors that are applied to each plan.



The stochastic runs generated 54 endpoints or branches for each of the eighteen (18) alternative resource plans for a total of 972 endpoints or branches. The results were used to develop risk profiles and tornado charts for all alternative resource plans.[62] Cumulative weights were then calculated and applied to each of the branches of the decision tree to allow for the calculation of the deterministic and stochastic PVRR for each alternative resource plan as shown in the following chart:

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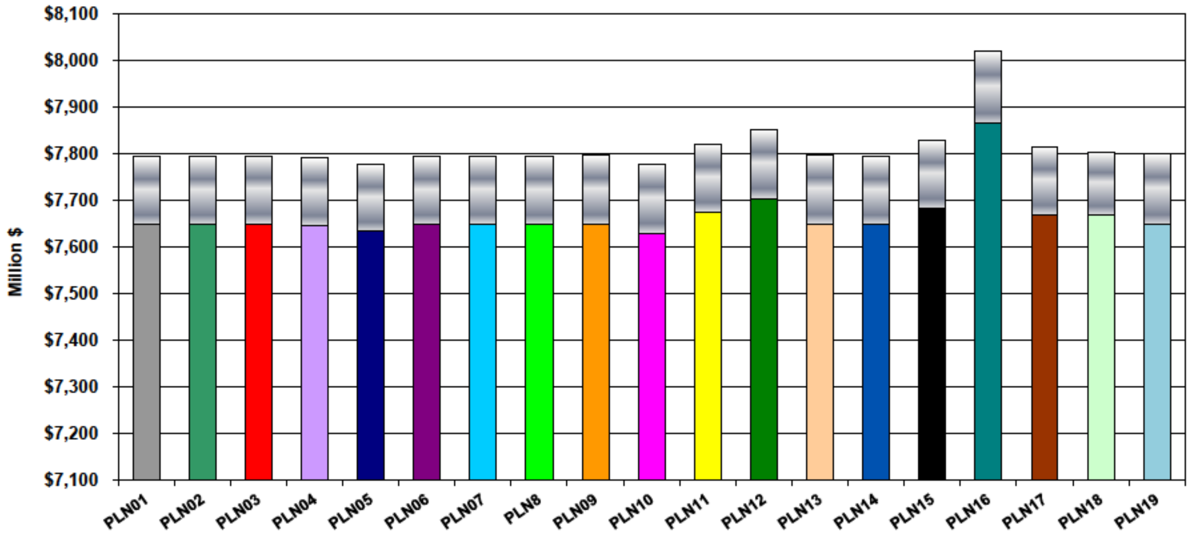
[59] IRP, Volume 6, page 5.
[60] Deterministic runs are used to determine the present value of revenue requirement before critical uncertain factors or a decision tree is applied.
[61] A stochastic process is one whose behavior is non-deterministic, in that a system's subsequent state is determined both by the process's predictable actions and by a random element.
[62] Tornado charts are found in Volume 6, Figures 6-144 through 6-173, and Figure 6-161. The risk profiles are found in Volume 6, Figure 6-174 and Figure 6-163.

PVRR with Risk Value (2016-2035) Deterministic + Stochastic[63]

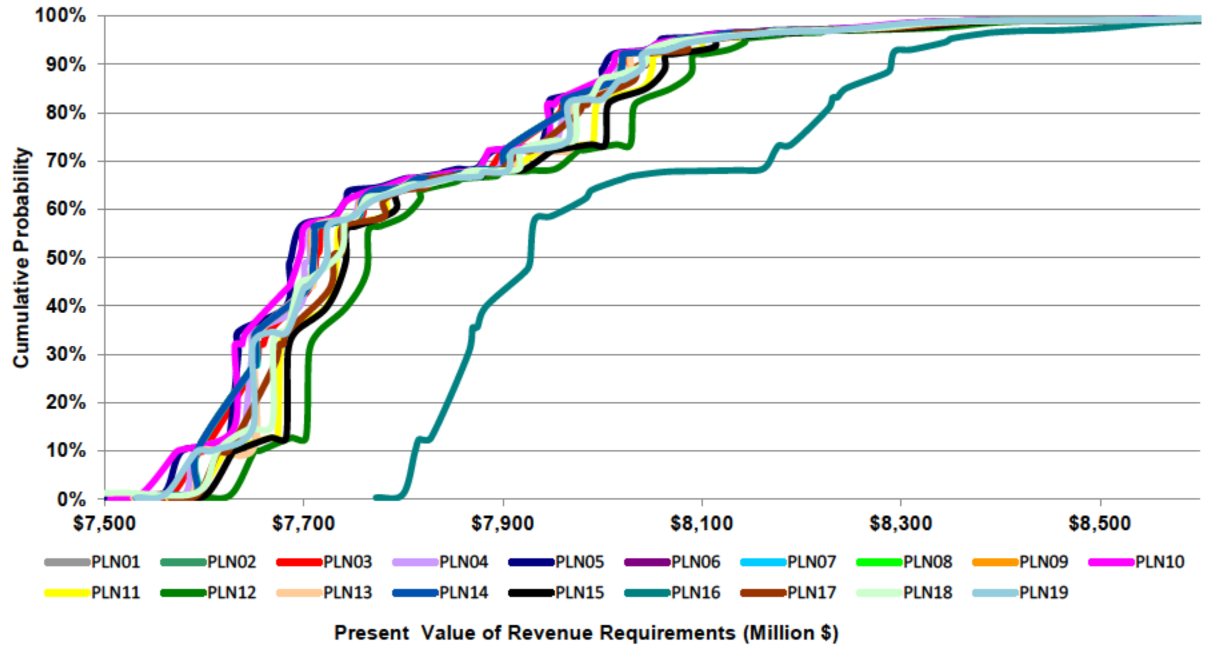


Finally, the cumulative probability distributions of PVRR – also known as risk profiles – were developed for each alternative resource plan. The cumulative probability distributions of PVRR for all alternative resource plans and for just the base resource plans are shown in the following charts:

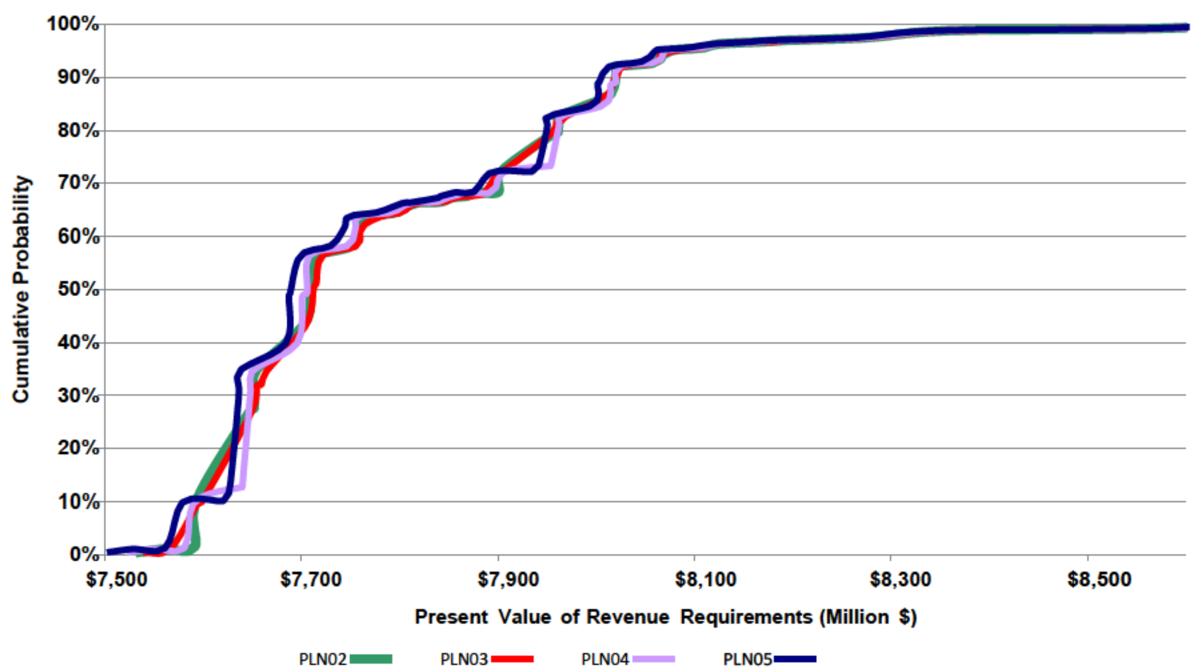
continued on next page

[63] IRP, Volume 6, page 154.

All Plans - Cumulative Probability of PVRR (2016 – 2035) [64]



Cumulative Probability of PVRR of Base Plans (2016-2035) [65]



[64] IRP, Volume 6, page 161.

[65] IRP, Volume 7, page 8

As a result of its review of Empire's integrated resource analysis, Staff found one deficiency and one concern regarding compliance with 4 CSR 240-22.060.

Deficiency 10 - Empire did not include any cost of utility financial incentives or lost earning opportunity in its alternative resource plans which have DSM resources as required by 4 CSR 240-22.060(4)(C).

Rule 4 CSR 240-22.060(4)(C) states:

> (4) Analysis of Alternative Resource Plans. The utility shall describe and document its assessment of the relative performance of the alternative resource plans by calculating for each plan the value of each performance measure specified pursuant to section (2). … The utility shall provide the following information: …
> (C) The analysis of economic impact of alternative resource plans, calculated with and without utility financial incentives for demand-side resources, shall provide comparative estimates for each year of the planning horizon—

The IRP includes the economic impacts without utility financial incentives for demand-side resources, but the IRP does not include economic impacts with utility financial incentives for demand-side resources as required by Rule 4 CSR 240-22.060(4)(C).

Staff performed an analysis of Empire's financial incentives or lost earnings opportunity for Plan 2 RAP DSM and for Plan 3 RAP+ DSM. Staff's analysis is included in Exhibit 1 of this Report.

To resolve this deficiency, Empire should analyze the economic impact of alternative resource plans, calculated with and without utility financial incentives for demand-side resources, and comparative estimates for each year of the planning horizon within its 2019 triennial compliance filing.

Concern B - Empire did not include cost effective renewable supply-side resources when performing its analysis for its all renewable alternative resource plan required by 4 CSR-240-22.060(3)(A)2.

Empire developed an all renewable alternate resource plan (Plan 19 Aggressive Renewable) as required by 4 CSR-240-22.060(3)(A)2. However, Empire included battery storage, landfill gas, and biomass as resources within this alternate resource plan. These renewable resource options have much higher capital costs than wind and solar technologies.

The costs and analysis descriptors of potential renewable supply-side resource options are shown in the table[66] below:

Costs and Analysis Descriptors of Potential Supply-Side Resource Options – Renewable and Storage Technologies[67]

	Wind	Biomass	Landfill Gas	Solar	Battery Storage
		Poultry Waste	Recip Engine	Photovoltaic	
Availability Factor	95.0%	90.0%	91.8%	98.0%	N/A
ISO Net Output, Full Load kW	50,000	5,000	5,000	10,000	10,000
Full Load Net Heat Rate, Btu/kWh	N/A	14,100	10,500	N/A	N/A
Capital Cost, $/kW (2015 $)	2,020	5,890	4,200	2,410	4,370
Fixed O&M, $/kW-year	24.48	120.00	180.00	19.50	59.60
Variable O&M, $/MWh	Included in FOM	10.00	20.00	Included in FOM	Included in FOM

To remedy this concern, Empire should develop an all renewable alternate resource plan that utilizes cost effective renewable supply-side resources within its 2019 triennial compliance filing.

Missouri Renewable Energy Standard ("RES")

The Missouri RES[68] requires investor-owned utilities to use eligible renewable energy resources to meet 15% of annual retail sales by 2021. Missouri's RES includes a carve-out for solar electricity and a credit multiplier of 1.25 for in-state generation. Compliance with the RES can be achieved through the development or procurement of renewable energy resources or by acquiring renewable energy credits[69] ("RECs"). RECs expire for Missouri compliance after 3 years from the date of generation.[70]

The Missouri RES includes a provision which allows the investor-owned utilities to adjust their RES compliance downward if the cost of compliance with the standard increases retail electricity rates by more than one percent. The retail rate impact is determined by estimating and comparing the electric utility's cost of compliance with least-cost renewable generation and the cost of continuing to generate or purchase electricity from entirely nonrenewable sources. The Missouri RES allows investor-owned utilities to invest in additional

66 IRP, Volume 4, Table 4-5.
67 IRP, Volume 4, page 21.
68 Section 393.1030, RSMo, Supp. 2009.
69 A REC represent that 1 MWh has been generated by a renewable energy resource.
70 RECs can be retired for compliance if valid at any time during the compliance year.

renewable resources, beyond those used for compliance, by excluding those resources from the retail rate impact calculation.[71]

The investor-owned utilities are required to file annual compliance reports and annual compliance plans[72] which describe how they will meet the standard for the current year and the two subsequent years. Empire's most recent compliance plan was filed in April 2016 in EO-2016-0279.

Empire's 2016 RES Compliance Plan outlined its plan to utilize existing renewable resources[73] for compliance with the Missouri RES from 2016 through 2018.

The table below includes Empire's forecasted Missouri RES requirements (solar and non-solar), existing REC production, and a projection of whether Empire will generate excess RECs for each corresponding year. All of the alternative resource plans that Empire has proposed (except for the all DSM scenario) include the addition of 100 MW of wind capacity in 2029. Plan 1 (Base Case) was originally created to be a low cost plan without forcing it to adhere to RES requirements. However, based on the planning assumptions and the capacity expansion model results, this plan complied with the RES requirement even without forcing the plan to do so.[74] Empire plans to meet its solar requirements through solar RECs ("S-RECs") acquired from its customer-generators and purchased S-RECs.

(HC): Forecasted RES Requirements and Projected Annual REC Excess

Year	Requirement	Forecasted RES Requirement (MWh)	Forecasted Solar RES Requirement (MWh)	MO Share Total Existing Non-solar Renewables Production (MWh)	Projected Annual REC Excess / (Deficit)
2016	5%	206,060	4,121	782,029	575,970
2017	5%	206,889	4,138	788,207	581,358
2018	10%	414,540	8,291	790,196	375,655
2019	10%	415,070	8,301	795,106	380,036
2020	10%	415,289	8,306	792,283	376,993
2021	15%	623,464	12,469	787,541	164,076
2022	15%	624,542	12,491	791,919	167,377
2023	15%	625,796	12,516	794,721	168,925

[71] 4 CSR 240-20.100(5)(A).
[72] 4 CSR 240-20.100(7).
[73] Elk River PPA, Meridian Way PPA, and Missouri Ozark Beach.
[74] IRP, Volume 6, page 9.

Year	Requirement	Forecasted RES Requirement (MWh)	Forecasted Solar RES Requirement (MWh)	MO Share Total Existing Non-solar Renewables Production (MWh)	Projected Annual REC Excess / (Deficit)
2024	15%	627,326	12,547	796,117	168,791
2025	15%	629,013	12,580	794,448	165,435
2026	15%	630,472	12,609	791,400	160,928
2027	15%	632,206	12,644	787,541	155,335
2028	15%	634,168	12,683	788,385	154,216
2029	15%	636,168	12,724	537,234	(98,950)
2030	15%	638,005	12,760	517,048	(120,957)
2031	15%	640,025	12,800	75,251	(564,774)
2032	15%	642,184	12,844	75,251	(566,933)
2033	15%	644,521	12,890	75,251	(569,270)
2034	15%	646,916	12,938	75,251	(571,666)
2035	15%	649,444	12,989	75,251	(574,193)

Rule 4 CSR 240-22.060(3) requires Empire to develop alternative resource plans to meet the planning objectives identified in rule 4 CSR 240-22.010(2). The goal outlined in 4 CSR 240-22.060(3) is to develop substantively different mixes of supply-side resources and demand-side resources and variations in the timing of resource acquisitions.

This section of Staff's report will focus on the interrelation of the Missouri Renewable Energy Standard (4 CSR 240-20.100) with the Electric Utility Resource Planning (4 CSR 240-22.060). For Chapter 22 filings, Empire is required to develop at least one alternative resource plan which incorporates renewable energy mandates for each of the following cases:

1. A compliance benchmark plan, minimally comply with legal mandates for demand-side and renewable energy resources (4 CSR 240-22.060(3)(A)1.);
2. An aggressive renewable energy resource plan, utilize only renewable energy resources, up to the maximum potential capabilities of renewable resources in the planning horizon (4 CSR 240-22.060(3)(A)2.); and
3. An optimal compliance resource plan, optimally comply with legal mandates for demand-side resources and renewable energy resources (4 CSR 240-22.060(3)(A)3.).

As a result of its review of Empire's integrated resource analysis, Staff has concluded that Empire has complied with the requirements established by 4 CSR 240-22.060(3)(A).

Staff Expert Witnesses: J Luebbert

4 CSR 240-22.070 RISK ANALYSIS AND STRATEGY SELECTION

Summary

This rule requires the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans and evaluate the demand-side resources that are included in the resource acquisition strategy.

The Resource Acquisition Strategy Selection Rule requires an evaluation of demand-side programs, demand-side rates, and load building programs in the strategy selection process and development of a 3-year implementation plan and contingency resource plans. The rule provides some flexibility in choosing the preferred plan, but requires the selection process for the preferred resource plan to be documented, including the relative weights given to various performance measures and the tradeoffs between competing plan objectives. The rule provides additional flexibility to exercise judgment when satisfying the policy objectives of Chapter 22, but also requires investments in advanced transmission and distribution technologies, includes demand-side programs that meet legal mandates and includes sufficient resources to serve load forecasted under extreme weather conditions. The rule requires the utility to officially adopt a preferred resource plan, contingency resource plans, and resource acquisition strategy, including specific information to describe the implementation plan.

Empire's decision-makers selected the preferred resource plan through the following decision process:

> Empire looked at the difference in the 20-year PVRR among these base plans as well as the 40-year PVRR basis to aid in its selection of the preferred plan. Plans 2, 3 and 4 are all very close with regard to PVRR, but Plan 5 has a lower PVRR. Therefore, considering all of the preferred plan selection criteria, and attempting to strike a balance over all of the planning objectives, Empire has selected the lowest cost base plan, Plan 5, the no DSM Scenario, as the preferred plan.[75]

[75] IRP, Volume 7, page 7.

Empire assessed the performance of all alternative resource plans in the High CO_2 scenario and concluded:

> Preferred Plan is the lowest cost plan for all uncertain factors under the High CO_2 scenario. That is, even when 100% probability is assigned to the uncertain factors in the table, the Preferred Plan is still the lowest cost plan.[76]

Empire determined the uncertain factors that may cause the company to modify the Preferred Plan are under the No CO_2 scenario for both low load and high market/gas prices. Should this scenario occur, Empire would select contingency resource plan identified as Plan 10 Low Load as its preferred resource plan.

Finally, Empire's 2016 – 2019 implementation plan for Plan 5 includes no demand-side resources and no change to its existing supply-side resources.[77]

As a result of its review of Empire's resource acquisition and strategy selection, Staff identified one concerns regarding compliance with 4 CSR 240-22.070.

Concern C - Empire has never performed evaluation, measurement and verification ("EM&V") for any of its DSM programs in compliance with 4 CSR 240-22.070(8) Evaluation of Demand-Side Programs and Demand–Side Rates.

To remedy this concern, Empire should comply with paragraph 13. c . of the Stipulation And Agreement[78] which was file in Case No. ER-2016-0023 on June 20, 2016 and was approved by the Commission on August 10, 2016.

Staff Expert Witnesses: John Rogers

4 CSR 240-22.080 FILING SCHEDULE, FILING REQUIREMENTS, AND STAKEHOLDER PROCESS

Summary

This rule specifies the requirements for electric utility filings to demonstrate compliance with the provisions of Chapter 22. The purpose of the compliance review required by Chapter 22 is not Commission approval of the substantive findings, determinations, or analyses contained

[76] IRP, Volume 7, page 22.
[77] IRP, Volume 7, pages 34 – 36.
[78] All programs will have impact and process evaluation, measurement and verification ("EM&V") performed by a third party independent contractor for the first two (2) full programs years at a budget of 5% of the actual expenditures for the two (2) full program years.

in the filing. The purpose of the compliance review required by Chapter 22 is to determine whether the utility's resource acquisition strategy meets the requirements of Chapter 22. However, if the Commission determines that the filing substantially meets these requirements, the Commission may further acknowledge that the preferred resource plan or resource acquisition strategy is reasonable in whole, or in part, at the time of the finding. This rule also establishes a mechanism for the utility to solicit and receive stakeholder input to its resource planning process.

The Filing Schedule, Filing Requirements, and Stakeholder Process Rule establish a filing deadline for all electric utilities on April 1 of each year. A triennial compliance filing is due every third year with more informal annual update filings during the years between the full triennial compliance filings. The annual updates are coupled with a stakeholder workshop to communicate changing conditions and utility plans and to seek comments and suggestions from stakeholders during the planning process. Preliminary plans are reviewed with stakeholders to receive input regarding potential concerns and deficiencies. However, once plans are filed, stakeholders again have the opportunity to identify potential concerns and deficiencies. The Commission, with input from stakeholders, will identify special contemporary issues each year for each utility to analyze during its planning process. To make the resource planning process more meaningful, the rule requires action from the utility if its business plan or acquisition strategy becomes inconsistent with the latest adopted preferred resource plan filed by the utility. The rule also requires certification that any request of action from the Commission is consistent with the utility's adopted preferred resource plan.

As a result of its review, Staff has identified no deficiencies or concerns related to 4 CSR 240-22.080 Filing Schedule, Filing Requirements, and Stakeholder Process.

Staff Expert Witnesses: John Rogers

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Empire District Electric Company's 2016 Triennial Compliance Filing Pursuant to 4 CSR 240-22	)))	**File No. EO-2016-0223**

AFFIDAVIT

State of Missouri)
) ss.
County of Cole)

COMES NOW Brad J. Fortson and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached Staff Report; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Brad J. Fortson
Brad J. Fortson

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of August, 2016.

JESSICA LUEBBERT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: February 19, 2019
Commission Number: 15633434

Jessica Luebbert
NOTARY PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Empire District Electric Company's 2016 Triennial Compliance Filing Pursuant to 4 CSR 240-22	)))	**File No. EO-2016-0223**

AFFIDAVIT

State of Missouri)
) ss.
County of Cole)

COMES NOW J Luebbert and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached Staff Report; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

J Luebbert

J Luebbert

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of August, 2016.

JESSICA LUEBBERT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: February 19, 2019
Commission Number: 15633434

Jessica Luebbert

NOTARY PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Empire District Electric Company's 2016 Triennial Compliance Filing Pursuant to 4 CSR 240-22	)))	**File No. EO-2016-0223**

AFFIDAVIT

State of Missouri)
) ss.
County of Cole)

COMES NOW John A. Rogers and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached Staff Report; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

John A Rogers

John A. Rogers

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of August, 2016.

JESSICA LUEBBERT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: February 19, 2019
Commission Number: 15633434

Jessica Luebbert

NOTARY PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Empire District Electric Company's 2016 Triennial Compliance Filing Pursuant to 4 CSR 240-22	)))	**File No. EO-2016-0223**

AFFIDAVIT

State of Missouri)
) ss.
County of Cole)

COMES NOW David C. Roos and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached Staff Report; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

David C. Roos

David C. Roos

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of August, 2016.

JESSICA LUEBBERT
Notary Public - Notary Seal
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Commissioned for Cole County
My Commission Expires: February 19, 2019
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Jessica Luebbert

NOTARY PUBLIC