MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT ON

THE EMPIRE DISTRICT ELECTRIC COMPANY

ELECTRIC UTILITY RESOURCE PLANNING COMPLIANCE FILING

FILE NO. EO-2019-0049

Jefferson City, Missouri
February 28, 2020

** <u>Denotes Confidential Information</u> **
*** <u>Denotes Highly Confidential Information</u> ***

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THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NO. EO-2019-0049

Executive Summary

On June 28, 2019, The Empire District Electric Company ("Empire" or "Company"), filed its 2019 Integrated Resource Plan ("IRP") triennial compliance filing ("Filing") in File No. EO-2019-0049, as required by 20 CSR 4240-22 Electric Utility Resource Planning.[1] Staff provides this Report as required by Commission Rule 20 CSR 4240-22.080(7):

> (7) The staff shall conduct a limited review of each triennial compliance filing required by this rule and shall file a report not later than one hundred fifty (150) days[2] after each utility's scheduled triennial compliance filing date. The report shall identify any deficiencies[3] in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies and shall provide at least one (1) suggested remedy for each identified deficiency. Staff may also identify concerns[4] with the utility's triennial compliance filing, may identify concerns related to the substantive reasonableness of the preferred resource plan or resource acquisition strategy, and shall provide at least one (1) suggested remedy for each identified concern.

As a result of its limited review, and as more fully discussed throughout this Report, Staff identified thirteen (13) deficiencies and five (5) concerns regarding Empire's IRP Filing.

The most serious deficiencies and concerns identified by Staff are Deficiency 3, Deficiency 10, Deficiency 11, Concern D and Concern E which collectively result in an IRP Filing which does not meet the requirements of Chapter 22,[5] because Empire's adopted preferred resource plan:

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[1] The Commission's March 18, 2019, *Order Granting Extension To File* extended Empire's 2019 triennial compliance filing from April 1, 2019, to July 1, 2019.

[2] The Commission's December 16, 2019 *Order Establishing Time to File Report* established February 28, 2020 as the deadline for Staff, Public Counsel and any intervenors to file their reports in this case.

[3] 20 CSR4240-22.020(9) Deficiency means deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and anything that would cause the electric utility's resource acquisition strategy to fail to meet the requirements identified in Chapter 22.

[4] 20 CSR 4240-22.020(6) Concern means concerns with the electric utility's compliance with the provisions of this chapter, any major concerns with the methodologies or analyses required to be performed by this chapter, 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.

[5] 20 CSR 4240-22.080(16) The commission will issue an order which contains its findings regarding at least one (1) of the following options:

(A) That the electric utility's filing pursuant to this rule either does or does not demonstrate compliance with the requirements of this chapter, and that the utility's resource acquisition strategy either does or does not meet the requirements stated in 4 CSR 240-22.

1. Adds renewable supply-side resources about 5 years prior to the actual need for such resources;
2. Over-values avoided capacity costs for the cost-effectiveness tests of its demand-side resources;
3. Proposes to implement demand-side programs which are not expected to provide benefits to all customers who pay for the programs; and
4. Is the result of an unclear decision analysis and strategy selection process used by Empire's decision-makers.

To remedy the most serious deficiencies and concerns identified by Staff, Staff recommends that Empire make a Chapter 22 annual update filing within 90 days of the Commission-approved joint filing in this case which:

1. Develops and analyzes three new alternative resource plans which postpone all new renewable resources in Plan 2, Plan 2B and Plan 4 until 2027 when such resources are needed to satisfy Southwest Power Pool ("SPP") resource adequacy requirements;[6]
2. Develops and analyzes three new alternative resource plans which postpone some or all new renewable resources in Plan 2, Plan 2B and Plan 4 beyond 2027 (when there is a need for supply-side resources to satisfy the SPP resource adequacy requirements) and also include a more robust portfolio of demand-side resources that can then claim actual avoided capacity costs;[7]
3. Includes a revised estimate of avoided capacity cost as a result of an actual avoided cost of capacity; and
4. Includes the use of a decision scorecard by Empire's decision-makers when selecting an adopted preferred resource plan and resource acquisition strategy.[8]

(B) That the commission approves or disapproves the joint filing on the remedies to the plan deficiencies or concerns developed pursuant to section (9) of this rule;

(C) That the commission understands that full agreement on remedying deficiencies or concerns is not reached and pursuant to section (10) of this rule, the commission will issue an order which indicates on what items, if any, a hearing(s) will be held and which establishes a procedural schedule; and

(D) That the commission establishes a procedural schedule for filings and a hearing(s), if necessary, to remedy deficiencies or concerns as specified by the commission.

[6] Such alternative resource plans could be Plan 2D, Plan 2BD and Plan 4D in Exhibit 4.

[7] Such alternative resource plans could be Plan DEE, Plan 2BDEE and Plan 4DEE in Exhibit 4.

[8] One example of a decision scorecard is in Exhibit 3.

List of Staff's Identified Deficiencies

Deficiency 1: Empire did not consider multiple levels of incentives paid by the utility for each end-use measure within a potential demand-side program, with corresponding adjustments to the maximum achievable potential and the realistic achievable potential of that potential demand-side program. This is not compliant with 20 CSR 4240-22.050(3)(G)5.B.

Deficiency 2: Empire did not provide an assessment of how the interactions between potential demand-side rates and potential demand-side programs would affect the impact estimates of the potential demand-side programs and potential demand-side rates. This is not compliant with 20 CSR 4240-22.050(4)(D)3.

Deficiency 3: The methodology used to calculate Empire's avoided demand cost is inconsistent with 20 CSR 4240-22.050(5)(A)1.

Deficiency 4: Empire did not provide the present worth of utility revenue requirements with financial performance incentives for demand-side resources the utility is planning to request. This is not compliant with 20 CSR 4240-22.060(2)(A)1.

Deficiency 5: Empire used the simple average of the 20-year estimate of the annual rates in determining the levelized annual average rate. This is not compliant with 20 CSR 4240-22.060(2)(A)4., 20 CSR 4240-22.020(29), 20 CSR 4240-22.060(2)(B), and 20 CSR 4240-22.020(64).

Deficiency 6: Empire used the 2020 single year rate increase due to the Commission-approved Customer Savings Plan as the maximum single-year increase in annual average rates. This is not compliant with 20 CSR 4240-22.060(2)(A)5.

Deficiency 7: Empire did not provide a plan in its IRP filing that was minimally compliant with legal mandates for demand-side resources, renewable energy resources, and other mandated energy resources to constitute a compliance benchmark resource plan. This is not compliant with 20 CSR 4240-22.060(3)(A)1.

Deficiency 8: Empire did not provide an analysis of economic impact of alternative resource plans, calculated with utility financial incentives for demand-side resources. This is not compliant with 20 CSR 4240-22.060(4)(C).

Deficiency 9: Empire did not provide a discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained. This is not compliant with 20 CSR 4240-22.060(4)(D).

Deficiency 10: The absence of alternative resource plans which postpone the timing of significant utility scale solar and/or distributed solar plus storage resource additions in the 2022 – 2023 time frame for Plan 2, Plan 2B and Plan 4 until these resource additions are needed in 2027 to meet SPP resource adequacy requirements is not in compliance with 20 CSR 4240-22.060(3).

Deficiency 11: Empire did not include the relative weights given to the various performance measures in selecting a preferred resource plan from among the alternative resource plans. This is not compliant with 20 CSR 4240-22.070(1).

Deficiency 12: Empire did not provide a process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled. This is not compliant with 20 CSR 4240-22.070(6)(G).

Deficiency 13: Empire did not provide all workpapers with formulas intact.

List of Staff's Identified Concerns

Concern A: Because Empire has overstated avoided capacity cost benefits when calculating the total resource cost test (TRC) results for its demand-side programs and portfolio, the programs may not be cost-effective and may not comply with 393.1075.4., SR Mo.

Concern B: In AEG's market characterization analysis performed in Empire's DSM market potential study, AEG removed the impacts from solar PV. By removing solar PV impacts, this increased Empire's historical sales and projected forecast. Staff is concerned that removing the impacts from solar PV installations from the baseline projections artificially increases Empire's historical sales and projected forecast and therefore artificially increases DSM market potential. In Staff's opinion, it would be more accurate

to include these impacts in a baseline projection for market consumption and DSM market potential.

<u>Concern C</u>: Empire did not reduce annual retail kWh sales for alternative resource plans with RAP and MAP demand-side resources relative to the annual retail kWh sales for Plan 3A when calculating annual average rates as required for compliance with 20 CSR 4240-22.060(4)(C)1.B.

<u>Concern D</u>: Empire's RAP portfolio may not provide benefits for all customers, regardless of whether the programs are utilized by all customers, as required by 393.1075.4.

<u>Concern E</u>: Because Empire's RAP portfolio 1) does not postpone the need for any supply-side resources, 2) derives nearly all of its benefits from a decrease in the revenue requirement for purchases plus sales in the SPP energy market, and 3) because SPP energy market price is a critical uncertain factor, the RAP portfolio is a risky investment for Empire's customers as a whole, especially those customers who do not participate in the programs, and may not be in compliance with Section 393.1075.4.

<u>Variance Request and Special Contemporary Issues</u>

On September 20, 2018, Empire filed an Application for Variances in File No. EO-2019-0049 seeking variances from portions of 20 CSR 4240-22.030 and 20 CSR 4240-20.094. On November 15, 2018, the Commission issued an Order Granting Variances.

On October 24, 2018, in File No. EO-2019-0066, the Commission issued an Order Establishing Special Contemporary Resource Planning Issues for Empire to analyze and document in its 2019 triennial compliance filing. Empire provided its response to these special contemporary issues in Volume 6 of its 2019 triennial compliance filing.

20 CSR 4240-22.010 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,[9] the Missouri Energy Efficiency Act of 2009[10] ("MEEIA"), and the Commission's MEEIA Rules.[11] Staff performed its review in this way because the policy objectives of Chapter 22 and of MEEIA are inseparable for electric utilities, since Rule 20 CSR 4240-22.010(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[12] 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. Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and

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[9] 20 CSR 4240-22 Electric Utility Resource Planning.
[10] 393.1075, RSMo.
[11] Amended 20 CSR 4240-20.092 and revised 20 CSR 4240-20.093 and 20 CSR 4240-20.094 became effective September 30, 2017.
[12] 20 CSR 4240-22.020(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."

> are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. The commission shall consider the total resource cost test a preferred cost-effectiveness test.

Because MEEIA is voluntary, electric utilities are not required to implement demand-side programs and a demand-side programs investment mechanism ("DSIM") under MEEIA and the Commission's MEEIA rules. However, electric utilities are required to comply with the Commission's 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 while also satisfying the legal mandates of Chapter 22, MEEIA and the MEEIA rules.

If a utility includes MEEIA programs and DSIM in its IRP's resource acquisition strategy's 3-year implementation plan, the utility should use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan subject to constraints due to rate impacts[13] in order to comply with MEEIA's legal mandate that programs result in energy or demand savings which are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. Staff uses the best practice in Appendix C of the National Standard Practice Manual[14] to guide its long-term assessment of the "equity" of benefits for customers who participate in programs and for customers who do not participate in programs through its analysis of rate impacts, bill impacts and energy efficiency participation levels. Appendix C of the National Standard Practice Manual is attached as Exhibit 1.

Staff Expert/Witness: Brad J. Fortson

[13] 20 CSR 4240-22.010(2)(C)3.
[14] https://nationalefficiencyscreening.org/national-standard-practice-manual/.

20 CSR 4240-22.030 Load Analysis and Forecasting

Summary

20 CSR 4240-22.030, 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 20 CSR 4240-22.050 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 describe and document why the selected load analysis methods best fulfill those purposes, and how the load analysis methods are consistent with one another and with the end-use consumption data used in the demand-side analysis as described in 20 CSR 4240-22.050.

Accurate models for electric power load forecasting are essential to the operation and planning of a utility company. Load forecasting helps an electric utility to make important decisions including decisions on purchasing and generating electric power, load switching, and infrastructure development. 20 CSR 4240-22.030 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 has used a Statistically Adjusted End-Use ("SAE") model for the residential and commercial classes and data borrowed from Itron's 2018 SAE West North Central region. SAE data contains adjustments for DSM programs and includes a forecast of photovoltaics. Regression model statistics show all variables are highly significant ($p \leq 0$) and the coefficient of determinations (R^2) ≥98 in all models statistics show the models are significant and represent the proportion of the variance for a dependent variable that is explained by an independent variable.

The Residential energy annual forecast (Fig. 3-22, PP. 11) shows smooth increasing until the year 2032, then stays relatively static for the following years. Compounded Annual Growth Rate ("CAGR") is *** ____ ***. The Commercial energy sales forecast (Fig 3-25, PP. 114) shows linear growth with the planning horizon and CAGR calculated 2020 through 2045 is *** ____ ***. For the planning forecast period of 2016 to 2035, CAGR of

Empire's retail energy sales-forecast and retail peak demand forecast are about *** ____ *** and *** ____ *** respectively.

Staff notes that Table 3-52 of the IRP Filing includes a *** ___ *** reduction in energy load forecast from 2019 to 2021 due to the end of wholesale contracts with three small towns. Further, the IRP Filing's capacity balance sheets include a peak load forecast reduction of *** ____________ *** from 2019 to 2021 due primarily to the end of wholesale contracts with 3 small towns. The total of retail sales and wholesale sales are important when meeting the SPP resource adequacy requirements and when planning changes in supply-side and demand-side resources.

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Staff has not identified any deficiencies and/or concerns. In Staff's opinion, the Integrated Resource analysis filing meets the Load Analysis and Load Forecasting requirements of 20 CSR 4240-22.030.

Staff Expert/Witness: Krishna Poudel

20 CSR 4240-22.040 Supply-Side Resource Analysis

Summary

Rule 20 CSR 4240-22.040 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, 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 options using the utility discount rate. 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 reviewed the following supply side resources for further investigation: [15]

1. Coal – supercritical coal with and without Carbon Capture & Storage ("CCS") or integrated gasification combined cycle with CCS
2. Natural gas-fired simple cycle – Aeroderivative Combustion Turbine ("CT"), E-class frame CT, F-class frame CT
3. Natural gas-fired combined cycle – 2 x 1 F Class and 2 x 1 Advanced Class
4. Natural gas-fired reciprocating engines
5. Traditional nuclear and small modular nuclear reactor
6. Wind – on-shore and off-shore, including re-powering of existing assets
7. Biomass – wood waste and poultry waste
8. Landfill gas
9. Solar photovoltaic ("PV") – fixed tilt and single axis tracking, with and without storage
10. Energy storage – lithium ion battery, lead acid battery, molten salt, Energy Vault concrete blocks
11. Combined heat and power ("CHP")
12. Electric vehicle charging infrastructure

Given Empire's size, current supply-demand balance and the expectation that new capacity needs associated with potential plant retirements in the future will be below 300 MW at any given point in time, it was assumed that partial ownership opportunities could exist for the various options, with a maximum block size of 200 MW. Therefore, each of the above options could be screened under its most ideal configurations to allow for a direct comparison of the different technologies.[16]

Empire performed two rounds of preliminary screening to determine a shortlist of supply-side candidate resource options prior to the full portfolio analysis. The first screening evaluated feasibility of the resource option within Empire's service territory or surrounding SPP region (described in Section 1.8), and the second screening compared the levelized cost of

[15] Empire's 2019 Triennial IRP filing 22.040 (pg.19).
[16] Empire's 2019 Triennial IRP filing 22.040 (pg.19).

electricity ("LCOE") associated with installed capital costs plus fixed and variable operation and maintenance costs for the potential resource options using the utility's discount rate.[17]

Upgrades to existing Empire plants were examined during the development of the IRP. These upgrades include:[18]

1. New pollution control systems were installed at the Iatan 1 unit. A scrubber, selective catalytic reduction ("SCR"), fabric filter, and powder activated carbon system were installed at Unit 1 in 2009.
2. New pollution control systems were installed at the Asbury 1 unit. Unit 1 is retrofitted with an SCR, scrubber, fabric filter, and a powder-activated carbon injection system. This air quality control system ("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 combined cycle ("CC") unit was completed in 2016.
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 has posted a $5.5 million asset retirement obligation ("ARO") for the Asbury pond closure costs. Empire expects resulting costs to be recovered in rates.[19]

Empire assigned transmission interconnection costs on a dollar per kilowatt basis for each candidate resource examined. It found that cost to be $69.90/kW in 2018 dollars and then escalates it by 2.5 percent per year. Empire is a member of the SPP and relies on SPP to determine which transmission lines will be built by members of SPP, when lines will be built, and the cost allocations to members of SPP for those lines. The SPP conducts studies directly associated with transmission planning and develops the transmission expansion plan ("STEP"). Since Empire's planned distribution system construction projects are not accounted for in the STEP, Empire provided details for its 2019-2024 construction budget in Appendix H to Volume 4.5 of its IRP.[20]

[17] Empire's 2019 Triennial IRP filing 22.040 (pg.24).
[18] Empire's 2019 Triennial IRP filing 22.040 (pg.19).
[19] Empire's 2019 Triennial IRP filing 22.040 (pg.43).
[20] Empire's 2019 Triennial IRP filing 22.040 (pg.63).

In 2018, 40 percent of Empire's generation was supplied by coal, 47 percent from natural gas, and 14 percent was provided by renewable sources. The remaining generation was provided by non-contract purchases. The 2018 system input by fuel type are shown in the following table.[21]

Power Plant Resource	Fuel Type	State	Interest (%)	Capacity (MW)	Start Date	Facility Age (Years)
Asbury 1	Coal	MO	100	200	1970	49
Iatan 1	Coal	MO	12	84	1980	39
Iatan 2	Coal	MO	12	106	2010	9
Plum Point	Coal	AR	7.52	51	2010	9
Riverton 10 CT[1]	Natural Gas	KS	100	13	1988	31
Riverton 11 CT	Natural Gas	KS	100	15	1988	31
Riverton 12 CT	Natural Gas	KS	100	247	2007	12
Empire Energy Center 1 CT	Natural Gas/Oil	MO	100	82	1978	41
Empire Energy Center 2 CT	Natural Gas/Oil	MO	100	80	1981	38
Empire Energy Center 3 CT	Natural Gas/Oil	MO	100	40	2003	16
Empire Energy Center 4 CT	Natural Gas/Oil	MO	100	40	2003	16
State Line CT	Natural Gas/Oil	MO	100	95	1995	24
State Line CC	Natural Gas	MO	60	292[2]	1997 & 2001[3]	22 &18
Ozark Beach	Hydro	MO	100	16	1913	106
Total Empire Installed Capacity				1,361		
Long Term Power Purchases		**Type**		**Capacity (MW)**	**End Date**	**Term**
Plum Point		Coal		50	2040	30 years
Elk River Wind Farm[4] (150 MW PPA)		Wind		22	2025	20 years
Meridian Way Wind Farm (105 MW PPA)[5]		Wind		9	2028	20 years
Capacity Summary						
Total Coal		Coal		441		
Total Gas Turbine		Gas		365		
Total Combined Cycle		Combined Cycle		539		
Total Hydro		Hydro		16		
Total Purchase includes wind		Purchased Power		81		
Total[6]		All		1,442		
1. Riverton 10 and 11 were manufactured in 1967 but were installed at Empire in 1988; they are 51 years old.						
2. Represents Empire's 60 percent share of a 495 MW State Line Combined Cycle unit.						
3. One of the gas turbines at State Line CC was installed in 1997 and hence is 21 years old. The other gas turbine and the steam turbine were installed in 2001.						
4. The Elk River Wind Farm consists of 100 1.5 MW turbines for a total of 150 MW. For purposes of the IRP, 15 MW of its installed capacity is counted toward Empire's reserve margin. This firm 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.						
5. The Meridian Way Wind Farm began commercial operation on December 15, 2008. The facility is rated at 105 MW and approximately 10 MW is counted toward Empire's reserve margin. This firm capacity is subject to rerating in the future.						
6. Empire is currently proposing the addition of 600 MW of nameplate capacity through three new wind farms. This would represent 90 MW of capacity credit.						

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

Rule 20 CSR 4240-22.040, 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

[21] Empire's 2019 Triennial IRP filing 22.040 (pg.10).

renewable technologies, which have the potential to be eligible for Missouri RES compliance, in its supply-side analysis:

1. Wind
2. Solar PV – Single Axis Tracking
3. Single Axis Tracking – Distributed
4. Solar PV –Fixed Tilt
5. Landfill Gas
6. Biomass

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 several alternative resource plans.

Staff has not identified any deficiencies or concerns related to Empire's supply-side resource analysis.

Staff Expert/Witness: Jordan Hull

20 CSR 4240-22.045 Transmission and Distribution Analysis

Summary

Rule 20 CSR 4240-22.045 Transmission and Distribution Analysis specifies minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting. Rule 20 CSR 4240-22.045 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 20 CSR 4240-22.045 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.

Staff has not identified any deficiencies or concerns related to Empire's transmission and distribution analysis.

Staff Expert/Witness: Jordan Hull

20 CSR 4240-22.050 Demand-Side Resource Analysis

Summary

Rule 20 CSR 4240-22.050, 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 20 CSR 4240-22.050 requires the assessment of Empire's technical potentials, maximum achievable potentials ("MAP"), and realistic achievable potentials ("RAP") and the selection of demand-side candidate resource options that are passed on to integrated resource analysis in Rule 20 CSR 4240-22.060.

Empire engaged Applied Energy Group ("AEG") to conduct a Demand-Side Management ("DSM") Potential Study to assess the future potential for savings through its programs and to identify refinements that will enhance savings. AEG first assessed Empire's service territory. The market assessment defined the market segments (building types, end uses, and other dimensions) that are relevant in the Empire service territory. AEG used detailed billing and customer data with minimal augmentation from secondary sources to allocate energy use and customers to the various sectors and segments. The total number of households and electricity sales for the service territory were obtained from Empire's customer database. AEG utilized commercial and industrial customer billing data and secondary sources to develop the commercial and industrial market segments. The nonresidential sector excludes customers that opt-out of Empire's DSM tariff (as of December 2017) and is segmented into small and large nonresidential segments based upon a 1,000 MWh annual use threshold. Customers with usage greater than or equal to the 1,000 MWh threshold were characterized as large nonresidential; all other customers were considered small nonresidential.

AEG analyzed potential demand-side resources for all major end uses as identified by the Residential Customer Energy Survey and secondary sources. The major end uses considered include:

- Residential sector: cooling, space heating, water heating, interior lighting, exterior lighting, appliances, electronics, and miscellaneous.
- Non-Residential sector: space heat, space cooling, ventilation, water heating, refrigeration, interior and exterior lighting, office equipment, food preparation, motors, process, and miscellaneous.

AEG developed eight program design scenarios to assess the optimal demand-side programs for potential further consideration. Programs were designed for the 20-year time period from 2020 to 2039, with 2020 representing a half-year to allow for implementation planning and contractor procurement. The recommended near-term demand-side management programs for 2020-2022 include:

- Residential Lighting
- Residential Behavioral
- Residential Whole House Efficiency
- Low Income Weatherization
- Low Income Behavioral
- Low Income Whole House Efficiency
- Commercial & Industrial Rebate

Additional programs are added to the portfolio after 2022 as measures and programs become cost effective. Many of these demand-side programs are dependent on advanced metering infrastructure necessary to support new DSM rate structures. There are also other business cases that were outside of the scope of the study that apply to the wider Empire company. While resources were identified as cost effective and included in the modeling, Empire anticipates following up with additional scoping studies and/or pilots to further study implementation designs.

AEG developed five energy efficiency portfolios based on what is assumed to be 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 Program Design Portfolio; (2) MAP Program Design Portfolio; (3) RAP- Portfolio; (4) RAP+ Portfolio; and (5) Aggressive Capacity Portfolio.

AEG assessed the three most common demand-side rate options for the Empire service territory for a multitude of different customer segments. Those demand-side rates are: (1) Time-of-Use; (2) Critical Peak Price; and (3) Real Time Pricing. The demand-side rates were screened for cost-effectiveness as stand-alone pilot programs. Programs that that were determined to be cost-effective by customer class were bundled together to assess overall impacts. To avoid double-counting of load reduction impacts, program-eligibility criteria were defined to ensure that customers do not participate in mutually exclusive programs at the same time.

Empire claims its avoided demand cost projections are based on a combination of sources that aim to develop a reasonable benchmark for the value of capacity. The following section presents Empire's rationale and drivers behind Empire's avoided demand cost projections for three distinct periods.

1. **Years 2019-2024:** The avoided demand cost projection for this time period is based on the mid-point between the levelized estimate of the Asbury plant's "going-forward" costs (fixed operations and maintenance costs and amortized new capital expenditures, less projected energy margins) and the fundamentally-derived ABB SPP capacity price forecast (which is close to zero today). The rationale for this approach is that while Empire is currently long on capacity, this situation is dependent on maintaining all capacity resources in the existing fleet. The Asbury plant currently has the highest going-forward costs and is thus the "marginal" retirement candidate. Therefore, the plant's going-forward costs are representative of the costs needed for Empire to avoid a capacity deficit.[22]

   Empire states that while Empire may have significant going-forward Asbury costs during this time period, the SPP market is generally oversupplied, suggesting little

[22] Empire's 2019 Triennial Compliance Filing, Vol. 5, pgs. 166 – 167.

fundamental value for capacity throughout SPP. With a surplus in SPP, Empire could, in theory, retire Asbury and find a less expensive bilateral capacity opportunity in the market.[23],[24] Therefore, the near-term avoided demand cost calculation splits the difference between the ABB capacity price and the Asbury going-forward cost.[25]

2. **Years 2025-2034:** The avoided demand cost projection for this time period is based on a transition to the full Asbury going-forward costs, as ABB's fundamental analysis indicates a growing value for capacity in the broader SPP market. The rationale for this approach is that as the excess capacity situation in SPP extinguishes over time due to regional plant retirements and growing load, Empire's avoided cost would be more closely based on the actual going-forward costs of Empire's existing fleet without a low-cost market backstop price.[26]

3. **Years 2035+:** The avoided demand cost projection for this time period is based on the cost of new entry ("CONE") for a new simple cycle combustion turbine ("CT"). The CT CONE includes capital costs, ongoing fixed operations and maintenance costs, and projects for transmission interconnection upgrade costs. According to the analysis, in 2035 and beyond, Asbury will have reached its end of life and Empire would need new capacity. The ABB fundamental forecast suggests similar dynamics in SPP, meaning that new entry pricing is a reasonable benchmark for avoided demand costs over the long-run throughout the whole market and specific to Empire.[27]

Deficiencies

Deficiency 1: Empire did not consider multiple levels of incentives paid by the utility for each end-use measure within a potential demand-side program, with corresponding adjustments to the maximum achievable potential and the realistic achievable potential of that potential demand-side program. This is not compliant with 20 CSR 4240-22.050(3)(G)5.B.

Rule 20 CSR 4240-22.050(3)(G)5.B. states:

[23] Empire's 2019 Triennial Compliance Filing, Vol. 5, pg. 167.
[24] Empire could also retire Asbury and not need any new resources until 2027 when new resources are needed to satisfy the SPP resource adequacy requirement since even a less expensive bilateral contract would not be needed until 2027.
[25] Ibid.
[26] Ibid.
[27] Ibid.

> (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 and 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;
>
> B. The cost of incentives paid by the utility to customers or utility financing to encourage participation in the potential demand-side program. The utility shall consider multiple levels of incentives paid by the utility for each end-use measure within a potential demand-side program, with corresponding adjustments to the maximum achievable potential and the realistic achievable potential of that potential demand-side program;

Empire provided the RAP Program Design cost of incentives or financing to encourage participation in the DSM programs. Empire states that the incentives varied depending on the RAP or MAP scenario analyzed. It does not appear that Empire analyzed any other level of incentives other than the RAP or MAP scenario. To remedy this deficiency, Empire should consider multiple levels of incentives paid by the utility for each end-use measure within a potential demand-side program as part of a MEEIA application filing and in future triennial compliance filings.

<u>Deficiency 2</u>: Empire did not provide an assessment of how the interactions between potential demand-side rates and potential demand-side programs would affect the impact estimates of the potential demand-side programs and potential demand-side rates. This is not compliant with 20 CSR 4240-22.050(4)(D)3.

Rule 20 CSR 4240-22.050(4)(D)3. 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:

> 3. An assessment of how the interactions between potential demand-side rates and potential demand-side programs would affect the impact estimates of the potential demand-side programs and potential demand-side rates;

Empire claims these interactions were assessed but did not provide the assessment. If the interactions were assessed in this triennial compliance filing, Empire should provide the assessment. If the interactions were not assessed in this triennial compliance filing, the assessment should be provided prior to the filing of a MEEIA application and in future triennial compliance filings.

Deficiency 3: The methodology used to calculate Empire's avoided demand cost is inconsistent with 20 CSR 4240-22.050(5)(A)1.

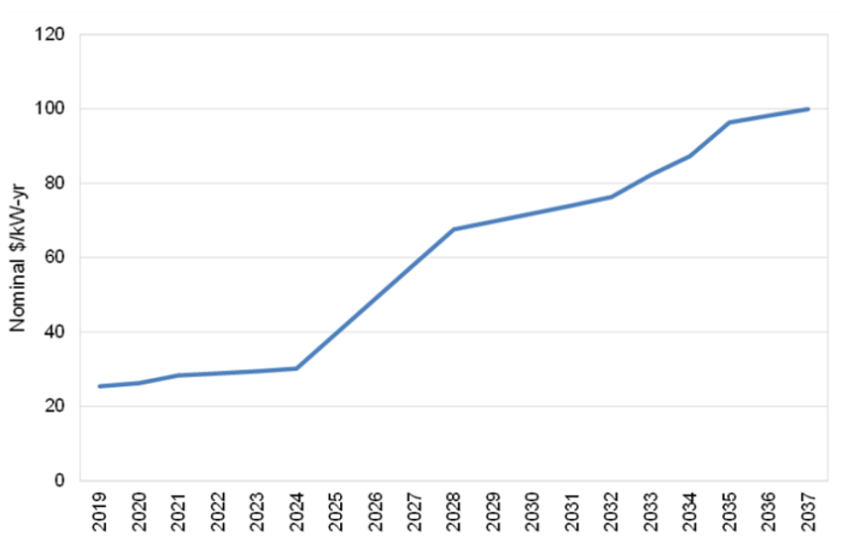
Rule 20 CSR 4240-22.050(5)(A)1 states:

> (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.
>
> (A) In each year of the planning horizon, the benefits of each potential demand-side program and each potential demand-side rate shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost. These calculations shall be performed both with and without the avoided probable environmental costs. The utility shall describe and document the methods, data, and assumptions it used to develop the avoided costs.
>
> (1) The utility avoided demand cost shall include the capacity cost of generation, transmission, and distribution facilities, adjusted to reflect reliability reserve margins and capacity losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs. The utility shall describe and document how it developed its avoided demand cost, and the capacity cost chosen shall be consistent throughout the triennial compliance filing.

Empire is not compliant with 20 CSR 4240-22.050(5)(A)1. with the calculation of its avoided capacity cost of generation, transmission, and distribution for purposes of DSM program screening. Overstating these costs results in artificial inflation of DSM program cost-effectiveness. The end result is that the model assumes programs are cost-effective when in fact they may not be. Because Empire does not require any supply-side resources to meet the SPP resource adequacy standard or to provide safe and adequate service to its customers, it is Staff's position that the avoided capacity cost should be zero until such time that Empire can actually avoid costs of capacity. Furthermore, Empire's decision to retire Asbury early may be a driving force for future Empire capacity needs, and may need to be addressed in more detail in another forum. Assuming avoided capacity costs from demand-side programs in the near term while simultaneously retiring Asbury without considering its capacity benefits is inconsistent with 20 CSR 4240-22.060(4).

Empire utilized ABB forecasted market prices as the avoided energy cost. ABB created a forward view of the SPP-KSMO regional electricity market using its Fall 2018 Reference Case data set. Empire also had access to the ABB forecasted capacity cost estimates in each year of the planning horizon. At most, Empire could have assumed the ABB forecasted capacity cost in the years in which Empire required capacity to meet SPP resource adequacy requirements. (Below are graphs showing avoided capacity cost that Empire filed in its 2019 IRP vs ABBs Midwest Fall 2018 Power Reference)[28]

Empires 2019 IRP Forecasted Electricity Market Price (nominal $/kW-year) Over the 20 year Planning Period



[28] Note that absent a need to meet SPP resource adequacy requirements Empire customers cannot avoid capacity costs.

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[redacted]

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To remedy this deficiency, Empire should 1) screen demand-side resources using zero avoided capacity costs until Empire needs capacity to meet SPP resource adequacy requirements at which point it could use the most recent ABB Midwest Power Reference Case as the avoided capacity cost for any near term MEEIA application and Chapter 22 compliance filing and calculate the TRC and other cost-effectiveness tests for those demand side programs that pass the screening and 2) select MEEIA programs which have TRCs greater than 1.00[29] and are expected to provide benefits for all customers.

As an alternative remedy, as part of its next Chapter 22 annual update, Empire should develop and analyze three new alternative resource plans which postpone some or all new renewable resources in Plan 2, Plan 2B and Plan 4 beyond 2027 (when there is a need for supply-side resources to satisfy the SPP resource adequacy requirements) and also include a more robust portfolio of demand-side resources which can then claim actual avoided capacity costs. Examples of such alternative resource plans could be Plan 2DEE, Plan 2BDEE and Plan 4DEE in Exhibit 4.

[29] 393.1075.4. … Programs targeted to low-income customers or general education campaigns do not need to meet a cost-effectiveness test, so long as the commission determines that the program or campaign is in the public interest. Nothing herein shall preclude the approval of demand-side programs that do not meet the test if the costs of the program above the level determined to be cost-effective are funded by the customers participating in the program or through tax or other governmental credits or incentives specifically designed for that purpose.

Concerns

<u>Concern A</u>: Because Empire has overstated avoided capacity cost benefits when calculating the total resource cost test (TRC) results for its demand-side programs and portfolio, the programs may not be cost-effective and may not comply with 393.1075.4., SR Mo.[30]

To remedy this concern, Empire should 1) screen demand-side resources using zero avoided capacity costs until Empire needs capacity to meet SPP resource adequacy requirements at which point it could use the most recent ABB Midwest Power Reference Case as the avoided capacity cost for any near term MEEIA application and Chapter 22 compliance filing and calculate the TRC and other cost-effectiveness tests for those demand-side programs that pass the screening; and 2) select MEEIA programs which have TRCs greater than 1.00[31] and are expected to provide benefits for all customers.

<u>Concern B</u>: In AEG's market characterization analysis performed in Empire's DSM market potential study, AEG removed the impacts from solar PV. By removing solar PV impacts, this increased Empire's historical sales and projected forecast. Staff is concerned that removing the impacts from solar PV installations from the baseline projections artificially increases Empire's historical sales and projected forecast and therefore artificially increases DSM market potential. In Staff's opinion, it would be more accurate to include these impacts in a baseline projection for market consumption and DSM market potential.

To remedy this concern, Empire should include solar PV installations in the unit consumption models and provide the updated models in its 2020 annual update.

Staff Experts/Witnesses: Brad J. Fortson and Jordan Hull

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[30] 393.1075.3. 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. … The commission shall consider the total resource cost test a preferred cost-effectiveness test.

[31] 393.1075.4. … Programs targeted to low-income customers or general education campaigns do not need to meet a cost-effectiveness test, so long as the commission determines that the program or campaign is in the public interest. Nothing herein shall preclude the approval of demand-side programs that do not meet the test if the costs of the program above the level determined to be cost-effective are funded by the customers participating in the program or through tax or other governmental credits or incentives specifically designed for that purpose.

20 CSR 4240-22.060 Integrated Resource Plan and Risk Analysis

Summary

This rule requires the utility to design alternative resource plans to meet the planning objectives identified in Rule 20 CSR 4240-22.010(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 establish minimum standards for the methods used to assess the risks associated with these uncertainties.

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 and its portfolio modeling consultant, Charles River Associates ("CRA"), developed, considered, and analyzed the present worth of long-run utility costs for 16 alternative resource plans by calculating the present value revenue requirements ("PVRR") for each. Empire and CRA utilized the minimization of long run utility costs (as expressed in terms of PVRR) as the primary criterion for the determination of the financial rank of each plan. Other factors, including risk, rate impact minimization, diversity, and probable environmental costs, were used to select the Preferred Plan. Risks associated with critical uncertain factors that could affect actual long-run costs and the risks associated with changing market prices, carbon regulation, capital and financing costs, and load were also evaluated for their potential impacts on the alternative resource plans. The alternative resource plans are shown in the following table.

Table 6-2 - Summary of Alternative Resource Plans

Plan	Plan Description	Renewable vs. Gas	Utility Scale vs. Distributed	Retirements	DSM Portfolio
0	Customer Savings Plan	Gas	Utility Scale	No Early Retirements	RAP
1	Asbury End of Life – Least Cost	Renewable	Utility Scale	No Early Retirements	RAP
2	Early Asbury Retire – Utility Scale Renewables	Renewable	Utility Scale	Asbury 2019	RAP
2B	Early Asbury Retire – Utility Scale Renewables - All 2023 Solar	Renewable	Utility Scale	Asbury 2019	RAP
2 - MAP	Early Asbury Retire – Utility Scale Renewables + MAP DSM	Renewable	Utility Scale	Asbury 2019	MAP
3	Early Asbury Retire – Utility Scale Thermal	Gas	Utility Scale	Asbury 2019	RAP
4	Early Asbury Retire – Distributed Renewable	Renewable	Distributed	Asbury 2019	RAP
5	Early Asbury Retire – Distributed Thermal	Gas	Distributed	Asbury 2019	RAP
6	Early Asbury Retire – Utility Scale Mix	Mix	Utility Scale	Asbury 2019	RAP
7	Early Asbury Retire – Distributed Mix	Mix	Distributed	Asbury 2019	RAP
8	Early Asbury, Peaker Re-tire - Utility Scale Re-newables	Renewable	Utility Scale	Asbury 2019; Energy Center Units 1&2 2021; Riv Units 10&11 2025	RAP
9	Early Asbury, Peaker Re-tire - Utility Scale Ther-mal	Gas	Utility Scale	Asbury 2019; Energy Center Units 1&2 2021; Riv Units 10&11 2025	RAP
10	Early Asbury, Peaker Re-tire - Distributed Renew-able	Renewable	Distributed	Asbury 2019; Energy Center Units 1&2 2021; Riv Units 10&11 2025	RAP
11	Early Asbury, Peaker Re-tire - Distributed Ther-mal	Gas	Distributed	Asbury 2019; Energy Center Units 1&2 2021; Riv Units 10&11 2025	RAP
12	Early Asbury, Peaker Re-tire - Utility Scale Mix	Mix	Utility Scale	Asbury 2019; Energy Center Units 1&2 2021; Riv Units 10&11 2025	RAP
13	Early Asbury, Peaker Re-tire - Distributed Mix	Mix	Distributed	Asbury 2019; Energy Center Units 1&2 2021; Riv Units 10&11 2025	RAP

Notes:
DSM – Demand-side Management
RAP – Realistic Achievable Potential
MAP – Maximum Achievable Potential

Empire's alternative resource plan development was centered broadly around three main planning considerations: (a) retirement options for Asbury and older peaking units (Energy Center 1&2, Riverton 10&11), (b) resource replacement technologies (renewable vs. thermal units), and (c) locational preferences (new utility scale vs. new distributed resources) for replacements. The retirement options include: (1) no early retirements, (2) retiring Asbury in 2019, and (3) retiring the peaking units early. Furthermore, each retirement option was linked to a set of replacement technologies, taking into account locational preferences. Most of the 16 alternative resource plans included common elements: "low" and "mid" cost bundle for RAP DSM, the Stateline Combined Cycle power plant upgrade, and the addition of 600 MWs of Empire-owned wind (in conjunction with a tax equity partner) in 2020. Additionally, all of the 16 alternative resource plans comply with Missouri RES requirements. A plan utilizing MAP DSM was also evaluated. Finally, Empire also included a Plan 0 as a bridge to Empire's previous Preferred Plan. Empire provided the following summary for each alternative resource plan.

- Plan 0 ("Customer Savings Plan"): Plan 0 was modeled to act as a "bridge" to Empire's previous Preferred Plan, which was updated in Empire's Change in Preferred Plan filing in File No. EO-2019-0106. Empire's previous Preferred Plan accelerates the timing of wind additions and changes the timing of some natural gas additions relative to Empire's 2016 IRP Preferred Plan. In particular, it adds 600 MW of utility-owned wind at the end of 2020, which was discussed and analyzed in Empire's Customer Savings Plan analysis. Empire's previous Preferred Plan also retires Asbury in 2035 and replaces it with a 214 MW natural gas combustion turbine in the same year. Plan 0 in the 2019 IRP has some changes from Empire's previous Preferred Plan: Energy Center 1 and 2 are both assumed to retire in 2026, and Empire builds a 148 MW natural gas aeroderivative unit rather than a combustion turbine. Plan 0 also includes a 35 MW upgrade at the Stateline Combined Cycle facility, as well as the "low-bundle" and "mid-bundle" of RAP DSM.
- Plan 1 (Asbury End of Life – Least Cost): Plan 1 is used to compare the relative costs and benefits of retiring Asbury early, which is tested in a number of the alternative resource plans. Plan 1 is similar to Plan 0, but instead of replacing Asbury in 2035 with

a natural gas aeroderivative unit, Plan 1 adds 100 MW of utility scale solar and 150 MW of utility scale solar + storage. Adding solar and solar + storage units was found to be the least-cost option when retaining Asbury through the end of its useful life. Plan 1 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 0.

- Plan 2 (Early Asbury Retire, Utility Scale Renewables): Plan 2 was developed to analyze the early retirement of Asbury and the costs and benefits of utility scale renewables. Plan 2 retires Asbury at the end of 2019. Due to the planned addition of 600 MW of utility scale wind in the plan, there is not an immediate capacity gap to fill. Plan 2 limits all capacity additions to utility scale renewables. Plan 2 builds 50 MW of solar in 2023, followed by another 50 MW of solar and 50 MW of solar + storage in 2027, 50 MW of solar in 2029, and 50 MW of solar + storage in 2034. Plan 2 was developed to analyze the effects of having both primarily utility scale resources and renewable resources under different possible future states of the world, including uncertainty around fuel prices, load, carbon prices, and capital costs. Plan 2 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 1.
- Plan 2B (Early Asbury Retire, 2023 Solar): Plan 2B was developed to test the effect of "over-building" utility scale solar in 2023 instead of the gradual buildup of solar in Plan 2. Overbuilding solar in 2023 can provide potential benefits since solar built by 2023 can qualify for 100% of the investment tax credit. Plan 2B builds 150 MW of utility scale solar in 2023, followed by 50 MW of utility scale solar + storage in 2027 and 50 MW of solar + storage in 2034. Plan 2B also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 2.
- Plan 2 - MAP (Early Asbury Retire, Central-Scale Renewables + MAP DSM): This plan was developed to test the effects of meeting future capacity needs with MAP DSM instead of RAP DSM. The "low-bundle" and "mid-bundle" of MAP DSM was selected in Plan 2 – MAP. This represents approximately 8 MW more of DSM capacity compared to RAP DSM by 2038. Plan 2 – MAP adds the same utility scale renewable resources as Plan 2. Plan 2 – MAP also adds the same Stateline Combined Cycle upgrade as Plan 2.
- Plan 3 (Early Asbury Retire, Utility Scale Thermal): Plan 3 was developed to analyze the early retirement of Asbury and the costs/benefit of owning utility scale thermal

resources. During its screen of potential resource options, Empire identified three main types of utility scale thermal units that were available as a potential resource option: natural gas combined cycle, a Wartsila natural gas peaking unit, and an aeroderivative natural gas peaking unit. Plan 3 selected natural gas aeroderivative units as the most economic utility scale thermal option. Plan 3 built two aeroderivative units, one in 2027 and one in 2034. Plan 3 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 2.

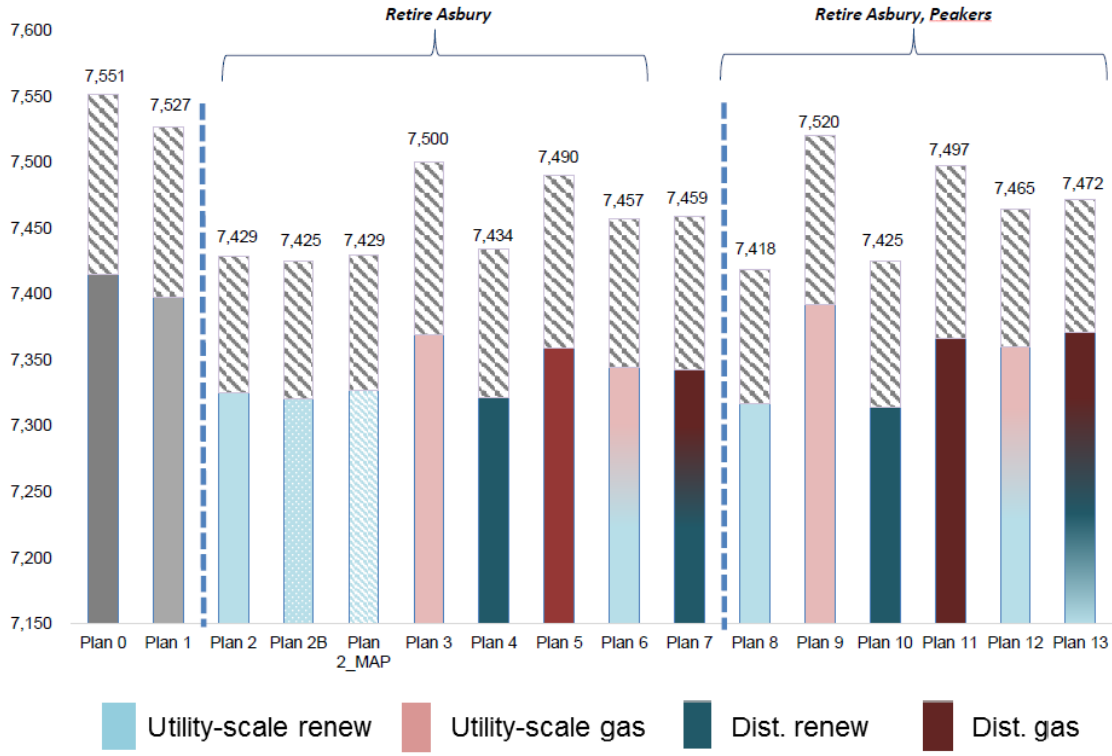
- Plan 4 (Early Asbury Retire, Distributed Renewable): Plan 4 was developed to analyze the value of building some level of renewables located at the distribution-level, instead of all new capacity additions being located at the utility scale level. Empire developed estimates for potential distribution system projects that could be avoided if replaced with a distributed energy resource. These avoided distribution costs informed the availability, size, and timing of potential distributed resource additions. Potential distributed renewable resource options included distributed solar, distributed storage, and distributed solar + storage. Plan 4 adds 19.5 MW of distributed solar + storage in 2022 and 2028 and 13.5 MW of distributed solar + storage in 2032 and 2036. Plan 4 also adds 50 MW of utility scale solar in 2023 and 2034, as well as 50 MW of utility scale solar + storage in 2027. Plan 4 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 3.
- Plan 5 (Early Asbury Retire, Distributed Thermal): Plan 5 was developed to analyze the value of building some level of thermal units located at both the distribution level and the utility scale level. Empire evaluated one distributed thermal resource option: a distribution-level Wartsila reciprocating unit. Plan 5 adds 7.4 MW of distributed Wartsila resource in 2022 and 2028, as well as 5 MW of distributed Wartsila in 2032 and 2036. Plan 5 also adds a 98 MW utility scale aeroderivative unit in 2027. Plan 5 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 4.
- Plan 6 (Early Asbury Retire, Central-Scale Mix): Plan 6 was developed to analyze the impacts of building both utility scale thermal and utility scale renewable resources. Plan 6 adds 50 MW of solar in 2023, 50 MW of solar + storage in 2027, a 49 MW aeroderivative in 2027, and 100 MW of solar in 2034. Plan 6 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 5.

- Plan 7 (Early Asbury Retire, Distributed Mix): Plan 7 was developed to analyze the impacts of building both distributed thermal and distributed renewable resources. Plan 7 adds 19.5 MW of distributed solar + storage in 2022, 50 MW of utility scale solar in 2023, a 49 MW aeroderivative in 2027, 7.5 MW of distributed gas in 2028, 13.5 MW of distributed solar + storage in 2032, 100 MW of utility scale solar in 2034, and 5 MW of distributed gas in 2036. Plan 7 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 6.
- Plan 8 (Early Asbury Retire, Peaker Retire, Utility Scale Renewables): Plan 8 was developed to analyze the early retirement of some of Empire's existing natural gas peaking units, Energy Center 1 and 2 and Riverton 10 and 11. Plan 8 retires Energy Center 1 and 2 at the end of 2021 and retires Riverton 10 and 11 at the end of 2025. Due to the larger capacity gap created by the Energy Center 1 and 2 retirements, Plan 8 builds 100 MW of utility scale solar in 2022, 50 MW of utility scale solar + storage in 2022, 50 MW of utility scale solar in 2023, and 50 MW of utility scale solar + storage in 2029. Plan 8 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 7.
- Plan 9 (Early Asbury Retire, Peaker Retire, Utility Scale Thermal): Plan 9 was developed to analyze the early retirement of Empire's existing natural gas peaking units and the effect of filling the capacity gap with utility scale thermal units. Plan 9 builds a 49 MW aeroderivative unit in 2022, a 49 MW aeroderivative unit in 2026, and a 49 MW aeroderivative unit in 2029. Plan 9 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 8.
- Plan 10 (Early Asbury Retire, Peaker Retire, Distributed Renewables): Plan 10 was developed to analyze the early retirement of Empire's existing natural gas peaking units and the effect of filling the capacity gap with both distributed-scale and utility scale renewables. Plan 10 builds 19.5 MW of distributed solar + storage in 2022, 100 MW of utility scale solar in 2022, 50 MW of utility scale solar + storage in 2022, 19.5 MW of distributed solar + storage in 2028, 13.5 MW of distributed solar + storage, and 13.5 MW of distributed solar + storage in 2036. Plan 10 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 9.

- Plan 11 (Early Asbury Retire, Peaker Retire, Distributed Thermal): Plan 11 was developed to analyze the early retirement of Empire's existing natural gas peaking units and the effect of filling the capacity gap with distributed thermal units along with utility scale thermal units. Plan 11 builds a 49 MW aeroderivative unit in 2022, a 7.5 MW distributed gas unit in 2022, a 49 MW aeroderivative unit in 2026, a 7.5 MW distributed gas unit, a 5 MW distributed gas unit in 2032, and a 5 MW distributed gas unit in 2036. Plan 11 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 10.
- Plan 12 (Early Asbury Retire, Peaker Retire, Utility Scale Mix): Plan 12 was developed to analyze the impacts of building both utility scale thermal and utility scale renewable resources. Plan 12 builds a 49 MW aeroderivative unit, 100 MW of utility scale solar in 2022, 50 MW of utility scale solar + storage in 2022, and 50 MW of utility scale solar in 2023. Plan 12 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 11.
- Plan 13 (Early Asbury Retire, Peaker Retire, Distributed Mix): Plan 13 was developed to analyze the impacts of building both distributed thermal and distributed renewable resources. Plan 13 builds a 49 MW aeroderivative unit in 2022, 100 MW of utility scale solar in 2022, 19.5 MW of distributed solar + storage in 2022, 50 MW of utility scale solar in 2023, 7.5 MW of distributed gas in 2028, 13.5 MW of distributed solar + storage in 2032, and 5 MW of distributed gas in 2036. Plan 13 also adds the same Stateline Combined Cycle upgrade and RAP DSM as Plan 12.

The stochastic PVRR for each of Empire's 16 alternative resource plans over the twenty-year planning period is shown in the following chart.

Figure 7-3 - PVRR with Risk Value for All Plans (2019-2038) – ($ millions)



<u>**Deficiency**</u>

<u>Deficiency 4</u>: Empire did not provide the present worth of utility revenue requirements with financial performance incentives for demand-side resources the utility is planning to request. This is not compliant with 20 CSR 4240-22.060(2)(A)1.

Rule 20 CSR 4240-22.060(2)(A)1. states:

> (2) Specification of Performance Measures. The utility shall specify, describe, and document a set of quantitative measures for assessing the performance of alternative resource plans with respect to resource planning objectives.
> (A) These performance measures shall include at least the following:
> 1. Present worth of utility revenue requirements, with and without any rate of return or financial performance incentives for demand-side resources the utility is planning to request;

By not providing the present worth of utility revenue requirements with financial performance incentives for demand-side resources the utility is planning to request, the full cost to ratepayers for the demand-side resources is understated which in turn overstates the net benefits to ratepayers of the demand-side resources. To remedy this deficiency, Empire should provide the present worth of utility revenue requirements with and without financial performance incentives for demand-side resources in its 2020 annual update filing and all future Chapter 22 triennial compliance filings.

Deficiency 5: Empire used the simple average of the 20-year estimate of the annual rates in determining the levelized annual average rate. This is not compliant with 20 CSR 4240-22.060(2)(A)4., 20 CSR 4240-22.020(29), 20 CSR 4240-22.060(2)(B), and 20 CSR 4240-22.020(64).

Rule 20 CSR 4240-22.060(2)(A)4. states:

> (2) Specification of Performance Measures. The utility shall specify, describe, and document a set of quantitative measures for assessing the performance of alternative resource plans with respect to resource planning objectives.
> (A) These performance measures shall include at least the following:
> 4. Levelized annual average rates;

Rule 20 CSR 4240-22.020(29) states:

> (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.

Rule 20 CSR 4240-22.060(2)(B) states:

> (2) Specification of Performance Measures. The utility shall specify, describe, and document a set of quantitative measures for assessing the performance of alternative resource plans with respect to resource planning objectives.
> (B) All present worth and levelization calculations shall use the utility discount rate and all costs and benefits shall be expressed in nominal dollars.

Rule 20 CSR 4240-22.020(64) states:

> (64) Utility discount rate means the post-tax rate of return on net investment used to calculate the utility's annual revenue requirements.

20 CSR 240-22.020(28) states, "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." Empire used a simple average of the 20-year estimate of the annual rates in determining the levelized annual average rate. This does not represent the levelized annual average rate as defined by the Chapter 22 rule.

To remedy this deficiency, Empire should recalculate the levelized annual average rate, as defined in the Chapter 22 rule, and provide the updated rate in its 2020 annual update and all future triennial compliance filings.

<u>Deficiency 6</u>: Empire used the 2020 single year rate increase due to the Commission-approved Customer Savings Plan as the maximum single-year increase in annual average rates. This is not compliant with 20 CSR 4240-22.060(2)(A)5.

Rule 20 CSR 4240-22.060(2)(A)5. states:

> (2) Specification of Performance Measures. The utility shall specify, describe, and document a set of quantitative measures for assessing the performance of alternative resource plans with respect to resource planning objectives.
> (A) These performance measures shall include at least the following:
> 5. Maximum single-year increase in annual average rates;

The 2020 single year rate increase includes 600 MWs of wind from the Commission-approved Customer Savings Plan which is included in each of the alternative resource plans. To appropriately assess the performance of alternative resource plans with respect to the maximum single year increase in annual average rates, the years after 2020 should be the basis for the maximum single year increase in annual average rates. To remedy this deficiency, Empire should reassess the maximum single year increase in annual average rates in the years after 2020 and provide the updated maximum single year increase in annual average rates in its 2020 annual update.

<u>Deficiency 7</u>: Empire did not provide a plan in its IRP filing that was minimally compliant with legal mandates for demand-side resources, renewable energy resources, and other mandated energy resources to constitute a compliance benchmark resource plan. This is not compliant with 20 CSR 4240-22.060(3)(A)1.

Rule 20 CSR 4240-22.060(3)(A)1. states:

> (3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of demand-side resources and supply-side resources to develop a set of alternative resource plans, each of which is designed to achieve one (1) or more of the planning objectives identified in 4 CSR 240-22.010(2).[32] Demand-side resources are the demand-side

[32] As part of the transfer of the Missouri Public Service Commission from the Department of Economic Development to the Department of Commerce and Insurance, effective August 28, 2019, all of the Missouri Public Service Commission's regulations have been transferred from the Economic Development's Title 4 to Commerce

> candidate resource options and portfolios developed in 4 CSR 240-22.050(6). Supply-side resources are the supply-side candidate resource options developed in 4 CSR 240-22.040(4). The goal is to develop a set of alternative plans based on substantively different mixes of supply-side resources and demand-side resources and variations in the timing of resource acquisition to assess their relative performance under expected future conditions as well as their robustness under a broad range of future conditions.
>
> (A) The utility shall develop, and describe and document, at least one (1) alternative resource plan, and as many as may be needed to assess the range of options for the choices and timing of resources, for each of the following cases. Each of the alternative resource plans for cases pursuant to paragraphs (3)(A)1. – (3)(A)5. shall provide resources to meet at least the projected load growth and resource retirements over the planning period in a manner specified by the case. The utility shall examine cases that –
>
> 1. Minimally comply with legal mandates for demand-side resources, renewable energy resources, and other mandated energy resources. This constitutes the compliance benchmark resource plan for planning purposes;

Because MEEIA is voluntary, there is no legal mandate for demand-side resources. Therefore, Empire should have developed an alternative resource plan that had no demand-side resources. Empire did not develop an alternative resource plan that had no demand-side resources as part of its triennial compliance filing. However, as a part of Staff's analysis, Staff requested Empire develop an alternative resource plan that had no demand-side resources. Empire provided Staff with this alternative resource plan as part of its response to Staff Data Request No. 0017 and this deficiency has been remedied for this triennial compliance filing. However, Empire should develop an alternative resource plan which complies with 20 CSR 4240-22.060(3)(A)1 and has no demand-side resources for all future Chapter 22 triennial compliance filing.

<u>Deficiency 8</u>: Empire did not provide an analysis of economic impact of alternative resource plans, calculated with utility financial incentives for demand-side resources. This is not compliant with 20 CSR 4240-22.060(4)(C).

Rule 20 CSR 4240-22.060(4)(C) states:

and Insurance's Title 20. This means that all the Commission's rules now start with 20 CSR 4240 instead of 4 CSR 240.

> (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). This calculation shall assume values for uncertain factors that are judged by utility decision makers to be most likely. The analysis shall cover a planning horizon of at least twenty (20) years and shall be carried out on a year-by-year basis in order to assess the annual and cumulative impacts of alternative resource plans. The analysis shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law. The analysis shall treat supply-side and demand-side resources on a logically-consistent and economically-equivalent basis, such that the same types or categories of costs, benefits, and risks shall be considered and such that these factors shall be quantified at a similar level of detail and precision for all resource types. 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—

Empire only provided an analysis of economic impact of alternative resource plans, calculated without utility financial incentives for demand-side resources. 20 CSR 4240-22.060(4)(C) requires this analysis of economic impact to also be calculated with utility financial incentives for demand-side resources to provide comparative estimates for each year of the planning horizon for the following performance measures for each year: 1) Estimated annual revenue requirement; 2) Estimated annual average rates and percentage increase in the average rate from the prior year; and 3) Estimated company financial ratios and credit metrics. Without the analysis of economic impact of alternative resource plans, calculated with and without utility financial incentives for demand-side resources, this comparison cannot be done. To remedy this deficiency, Empire should provide an analysis of economic impact of alternative resource plans, calculated with and without utility financial incentives for demand-side resources, and provide the comparative estimates required by Chapter 22. The analysis should be provided in Empire's 2020 annual update filing and all future triennial compliance filings.

Deficiency 9: Empire did not provide a discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained. This is not compliant with 20 CSR 4240-22.060(4)(D).

Rule 20 CSR 4240-22.060(4)(D) 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). This calculation shall assume values for uncertain factors that are judged by utility decision makers to be most likely. The analysis shall cover a planning horizon of at least twenty (20) years and shall be carried out on a year-by-year basis in order to assess the annual and cumulative impacts of alternative resource plans. The analysis shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law. The analysis shall treat supply-side and demand-side resources on a logically-consistent and economically-equivalent basis, such that the same types or categories of costs, benefits, and risks shall be considered and such that these factors shall be quantified at a similar level of detail and precision for all resource types. The utility shall provide the following information:
>
> > (D) A discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained;

Empire states, "A residential customer class price elasticity of -0.1 and a commercial customer class price elasticity of -0.15 were incorporated into the load forecast (addressed in Volume 3), which became the basis for all alternative plans." However, there appears to be no mention of price elasticity in Volume 3. Therefore, a discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained, as required by 20 CSR 4240-22.060(4)(D), is missing from Empire's triennial compliance filing. To remedy this deficiency, Empire should provide a discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained and provide this information in its 2020 annual update filing and all future triennial compliance filings.

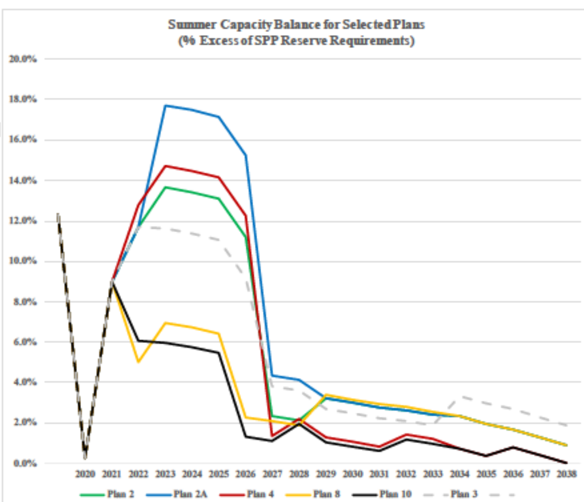
<u>Deficiency 10</u>: The absence of alternative resource plans which postpone the timing of significant utility scale solar and/or distributed solar plus storage resource additions in the 2022 – 2023 time frame for Plan 2, Plan 2B and Plan 4 until these resource additions are needed in 2027 to meet SPP resource adequacy requirements is not in compliance with 20 CSR 4240-22.060(3).

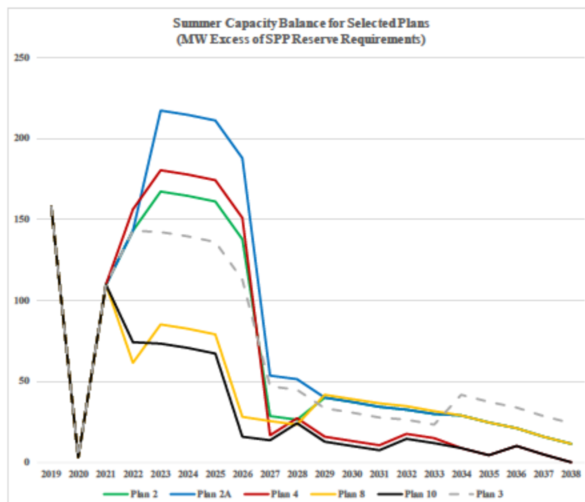
Rule 20 CSR 4240-22.060(3) states:

> (3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of demand-side resources and supply-side resources to develop a set of alternative resource plans, each of which is

designed to achieve one (1) or more of the planning objectives identified in 4 CSR 240-22.010(2). Demand-side resources are the demand-side candidate resource options and portfolios developed in 4 CSR 240-22.050(6). Supply-side resources are the supply-side candidate resource options developed in 4 CSR 240-22.040(4). The goal is to develop a set of alternative plans based on substantively different mixes of supply-side resources and demand-side resources and variations in the timing of resource acquisition to assess their relative performance under expected future conditions as well as their robustness under a broad range of future conditions.

Staff notes that each of the three alternative resource plans which Empire's decision-makers considered as finalist when selecting its preferred resource plan (Plan 2, Plan 2B and Plan 4) each add capacity from 2022 – 2026 in excess of what is necessary to meet SPP resource adequacy requirements.





To remedy this deficiency Empire should develop, analyze and document the performance of three new alternative resource plans which postpone all resource additions in the 2022 – 2023 time frame for Plan 2, Plan 2B and Plan 4 until 2027 when such resources are needed to meet SPP resource adequacy requirements as part of its next Chapter 22 annual update filing. Examples of such alternative resource plans could be Plan 2D, Plan 2BD and Plan 4D in Exhibit 4.

Concern

Concern C: Empire did not reduce annual retail kWh sales for alternative resource plans with RAP and MAP demand-side resources relative to the annual retail kWh sales for Plan 3A[33] when calculating annual average rates as required for compliance with 20 CSR 4240-22.060(4)(C)1.B.

To remedy this concern, Empire should reduce annual kWh consistent with the annual energy savings expected from demand-side resources when calculating annual average rates in future MEEIA applications and Chapter 22 triennial compliance filings.

Staff Expert/Witness: Brad J. Fortson

4 CSR 240-22.070 Resource Acquisition 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 Plan 4 as the preferred resource plan. Plan 4 includes the near-term retirement of Asbury, as well as the low and mid-cost bundles of RAP

[33] Staff Data Request No. 0017.

DSM and a mix of utility-scale and distributed solar and solar plus storage resources. Plan 4 also includes the addition of 600 MW of Empire owned wind generation in place by the end of 2020, the upgrade of the Stateline Combined Cycle unit, and 10 MW of community solar in 2021.

The preferred resource plan includes the following retirements of Empire's existing units:

- The retirement of Asbury in 2019;
- The retirements of Energy Center 1 and Energy Center 2 in 2026; and
- The retirements of Riverton units 10 and 11 in 2033

All other existing Empire generating units are assumed to continue operations throughout the planning horizon. Empire's two existing wind contracts are assumed to expire during the planning period. The 105 MW Meridian Way 20-year wind purchased power agreement ("PPA") will expire in December 2028, and 150 MW Elk River 20-year wind PPA will expire in 2025. Empire does not plan to extend either contract.

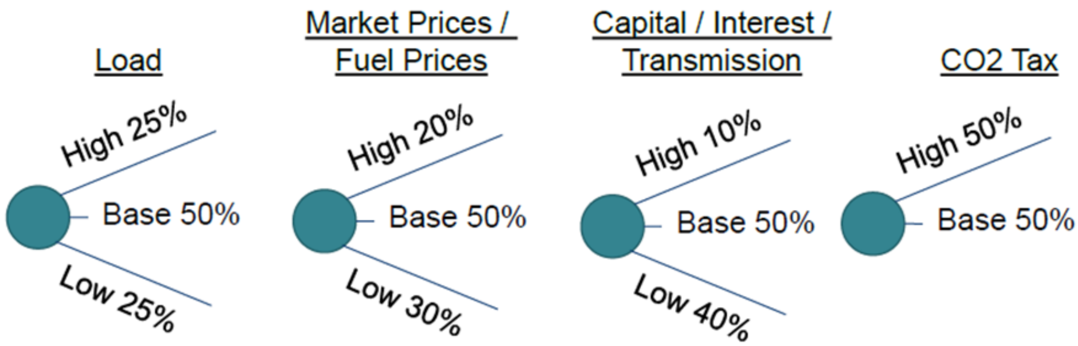
Empire's preferred resource plan includes:

- 600 MW of wind added at the end of 2020;
- Utility-scale solar added in 2023 (50 MW) and 2034 (50 MW);
- Distributed solar in 2021 (10 MW of community solar);
- Utility-scale solar plus storage added in 2027 (50 MW); and
- Distributed solar plus storage added in 2022 (19.5 MW), 2028 (19.5 MW), 2032(13.5 MW), and 2036 (13.5 MW)

The Confidential version of the summer capacity balance sheet and winter capacity balance sheet for Plan 4 are included as Confidential Exhibit 2.

Empire identified the following critical uncertain factors:[34] environmental costs, market prices/fuel prices, load, and capital/transmission/interest costs. These critical uncertain factors and their ranges form the nodes and the branches of the following uncertainty tree.

[34] 20 CSR 4240-22.020(8) Critical uncertain factor is any uncertain factor that is likely to materially affect the outcome of the resource planning decision.



Empire is considering Plans 2, 2-MAP, 3, 5, 6, and 7 as contingency plans that may address differing futures for loads, fuel prices, environmental costs, and capital costs. Empire will continue to monitor all uncertain factors, file annual updates, and file triennial compliance filings with advanced notice should a new resource be required earlier than expected by this 2019 triennial compliance filing.

Deficiencies

Deficiency 11: Empire did not include the relative weights given to the various performance measures in selecting a preferred resource plan from among the alternative resource plans. This is not compliant with 20 CSR 4240-22.070(1).

Rule 20 CSR 4240-22.070(1) states:

> (1) The utility shall select a preferred resource plan from among the alternative resource plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060. The utility shall describe and document the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall provide the names, titles, and roles of the utility decision-makers in the preferred resource plan selection process.

Empire's resource acquisition strategy selection process did not describe and document the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision-makers to judge the appropriate trade-offs between competing planning objectives and between expected performance and risk. To remedy this deficiency, Empire should describe and document the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by the utility decision-makers to judge the appropriate trade-offs between competing planning objectives and between expected performance and risk. Empire did not use minimization of the present worth of long-run utility costs as the only selection criterion when choosing its adopted preferred resource plan in its 2019 triennial compliance filing. Empire should utilize a decision scorecard in its 2020 annual update and all future triennial compliance filings and annual update filings. For example, Exhibit 3 is the decision scorecard used by Ameren Missouri in its 2018 Chapter 22 triennial compliance filing in File No. EO-2018-0038.

<u>Deficiency 12</u>: Empire did not provide a process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled. This is not compliant with 20 CSR 4240-22.070(6)(G).

Rule 20 CSR 4240-22.070(6)(G) states:

> (6) The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the preferred resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain—
>
> (G) A process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled.

In reference to 20 CSR 4240-22.070(6)(G), Empire states, "The performance measures of the preferred resource plan required by rule for each year of the planning horizon are presented below in Figure 7-17. These measures include: estimated annual revenue requirement; estimated level of average retail rates and percentage of change from the prior year; and estimated company financial ratios. The annual results of the performance measures are illustrated in Figure 7-28 through Figure 7-34 that follow." Empire did not provide a process for monitoring the progress made toward implementing the preferred resource plan or for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled.

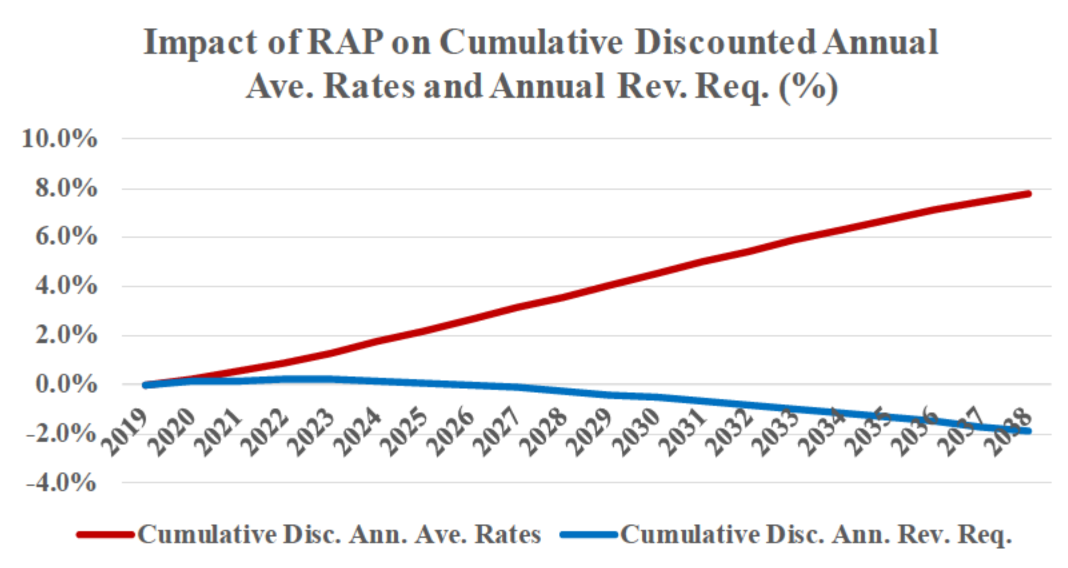
To remedy this deficiency, Empire should provide, in its 2020 annual update filing and all future triennial compliance filings, a process for monitoring the progress made toward implementing the preferred resource plan or for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled.

Concern

Concern D: Empire's RAP portfolio may not provide benefits for all customers, regardless of whether the programs are utilized by all customers, as required by 393.1075.4.

Staff uses the best practice in Appendix C of the National Standard Practice Manual[35] to guide its long-term assessment of the **equity** of benefits for customers who participate in programs and for customers who do not participate in programs through its analysis of rate impacts, bill impacts and energy efficiency participation levels. Empire's DSM program participation levels will likely be low as a result of the relatively low level of annual program spending for the RAP portfolio. Because the RAP portfolio does not postpone any supply-side resources and because Staff estimates that cumulative discounted annual average rates will increase more than four (4) times the reduction in cumulative discounted annual revenue requirements, it is unlikely that customers who do not participate in demand-side programs will receive any overall benefits from the programs.

[35] https://nationalefficiencyscreening.org/national-standard-practice-manual/.

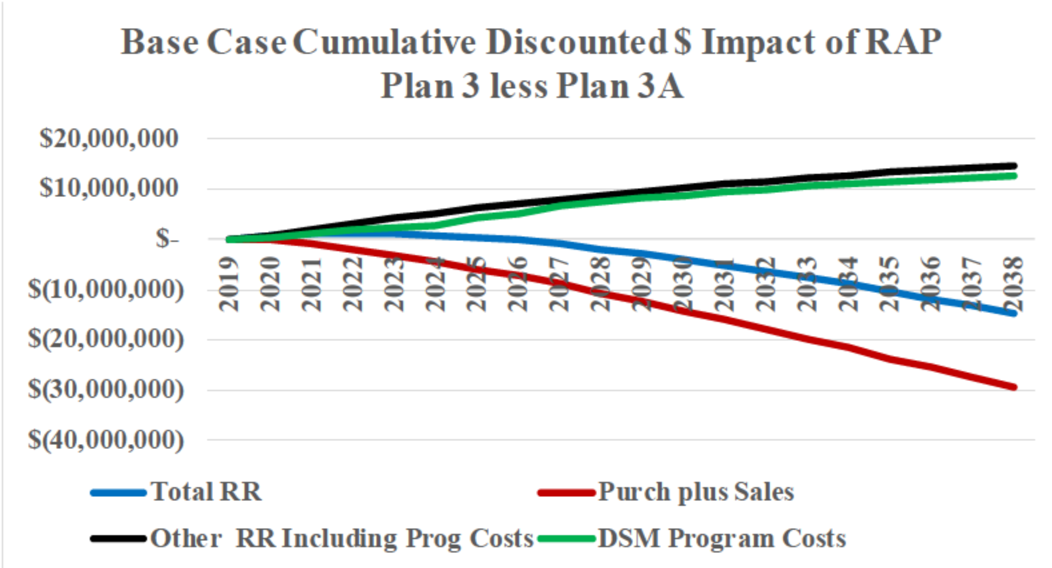


To remedy this concern, Empire should work with its stakeholders prior to filing any MEEIA application to help assure that such a MEEIA application complies with MEEIA.

<u>Concern E</u>: Because Empire's RAP portfolio 1) does not postpone the need for any supply-side resources, 2) derives nearly all of its benefits from a decrease in the revenue requirement for purchases plus sales in the SPP energy market, and 3) because SPP energy market price is a critical uncertain factor, the RAP portfolio is a risky investment for Empire's customers as a whole, especially those customers who do not participate in the programs, and may not be in compliance with Section 393.1075.4.

Staff's analysis of data for the Base Case (Iteration 1) from CRA's integrated resource analyses for Plan 3 and for Plan 3A[36] determined that all of the reduction to annual revenue requirements for the RAP portfolio are the result of changes in the energy purchases plus sales in the SPP marketplace and that nearly all of the increase to annual revenue requirements are due to the program cost for demand-side resources.

[36] Staff Data Request No. 0017.



To remedy this concern, Empire should work with its stakeholders prior to filing any MEEIA application to help assure that such a MEEIA application complies with MEEIA.

Staff Expert/Witness: Brad J. Fortson

<u>4 CSR 240-22.080 Filing Schedule and Requirements</u>

<u>Summary</u>

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 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 establishes 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.

Deficiency

Deficiency 13: Empire did not provide all workpapers with formulas intact.

Rule 20 CSR 4240-22.080(11) states:

> (11) All workpapers, documents, reports, data, computer model documentation, analysis, letters, memoranda, notes, test results, studies, recordings, transcriptions, and any other supporting information relating to the filed resource acquisition strategy within the electric utility's or its contractors' possession, custody, or control shall be preserved and submitted within two (2) days of its triennial compliance or annual update filings in accordance with any protective order to the staff and public counsel, and to any intervenor within two (2) days of the intervenor signing and filing a confidentiality agreement, for use in its review of the periodic filings required by this rule. All information shall be labeled to reference the sections of the technical volume(s) to which it is related, and all spreadsheets shall have all formulas intact. Each electric utility shall retain at least one (1) readable copy of the officially adopted resource acquisition strategy and all supporting information for at least the prior three (3) triennial compliance filings.

In Staff Data Request No. 0011, Staff requested that all workpapers be provided with links and formulas intact. CRA responded that its financial model is a macro-based Excel tool that is not easily converted to a live formula setup, so workpapers with formulas intact could not be provided. To remedy this deficiency, Empire and CRA should work with stakeholders to determine an adequate solution to this deficiency for future triennial compliance filings and annual update filings.

Staff Expert/Witness: Brad J. Fortson

Appendix C. Accounting for Rate and Bill Impacts

The Rate Impact Measure test is not appropriate for cost-effectiveness analyses for several reasons. Nonetheless, the impacts of EE resources on customer rates and bills is sometimes of great interest to regulators and other stakeholders. This appendix describes a better approach for assessing rate and bill impacts of EE resources through long-term independent assessments of rate impacts, bill impacts, and participation rates.

C.1 Multiple Factors Affecting Rate Impacts

Efficiency resources can affect electricity and gas rates in several ways. First, they will create upward pressure on rates as a result of (a) the recovery of efficiency program administration and implementation costs; and (b) the recovery of lost revenues resulting from EE programs.

Second, they will create downward pressure on rates as a result of avoided costs, including:

- reduced generation capacity costs
- reduced T&D costs, including reduced line losses;
- reduced environmental compliance costs;
- reduced utility credit and collection costs;
- reduced wholesale market prices from price suppression effects, in regions with wholesale electricity markets; and
- reduced average fuel costs, in regions without wholesale electricity markets, as a result of reducing the consumption of the marginal fuels.

The net impact of efficiency resources on electricity and gas rates will be a result of all these different factors combined. Some of these impacts (such as recovery of program costs, wholesale market price suppression effects, and reduced average fuel costs) might occur over the short term, while others (such as reduced generation, transmission, and distribution capacity costs) might occur over a longer time period.

Understanding the impact of lost revenues is essential to understanding the impact of efficiency resources on rates. Lost revenues are the main reason why efficiency resources can be highly cost-effective and yet still result in rate increases. An efficiency resource might pass the UCT, where the long-term utility system benefits are significantly greater than the long-term utility system costs, but still result in increased rates if the lost revenues are high enough. This is often the case in practice where many efficiency programs are cost-effective according to the UCT, but not according to the RIM test.[52]

The recovery of lost revenues is one of the factors that distinguish the impacts of supply-side resources from those of EE resources (as well as all DERs). Supply-side resources do not create lost revenues, because they do not reduce customer consumption.

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[52] The only difference between the Utility Cost test and the RIM test is that the latter includes lost revenues as one of the costs of EE resources.

Therefore, an EE resource might be much more cost-effective than a supply-side resource, but still result in upward pressure on rates as a result of the lost revenues.

Furthermore, the timing and impact on rates due to the recovery of lost revenues will depend upon the frequency of utility rate cases. In the years in between utility rate cases, the base rates are typically not increased to allow for the recovery of lost revenues. Instead, the lost revenues will result in reduced earnings for the utility, all else being equal. However, in those cases where the utility has some form of a decoupling mechanism, rates will be adjusted between rate cases and utility earnings will not be affected by the lost revenues.

The RIM test was originally intended to indicate the impact on rates from EE resources (CPUC 2001, 13). However, this test does not provide useful information regarding efficiency resource cost-effectiveness, as described below.

C.2 Limitations of the Rate Impact Measure Test

One of the main limitations of the RIM test is that it does not provide useful information about what happens to rates as a result of efficiency resource investments. A RIM benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact, in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM test results do not provide any context for utilities and regulators to consider the magnitude and implications of the rate impacts.

Another significant problem with the RIM test is that it typically does not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal, and if the test is applied properly). However, achieving the lowest rates is not the sole or primary goal of efficiency resource assessment. Maintaining low utility system costs, and therefore low customer bills, often has priority over minimizing rates. For most customers, the size of the electricity bills that they must pay is more important than the rates underlying those bills.

In addition, a strict application of the RIM test can lead to perverse outcomes. The RIM test can lead to the rejection of significant reductions in utility system costs to avoid what may be insignificant impacts on customers' rates. For example, a particular efficiency program might offer hundreds of millions of dollars in net benefits under the UCT (i.e., net reductions in utility system costs), but be rejected as not cost-effective if it fails the RIM test. It may well be that the actual rate impact is likely to be so small as to be unnoticeable. Rejecting such large reductions in utility system costs to avoid *de minimus* rate impacts is not in the best interests of customers overall.

Another important problem with the RIM test is that it is not consistent with basic economic theory. The lost revenues from EE are not a new cost created by investments in efficiency resources. Price impacts from lost revenues are caused by the need to recover existing costs over fewer sales. These existing costs that would be recovered through rate increases are not caused by the efficiency resources themselves, they are caused by historical investments in supply-side resources that become fixed costs. In economic terms, these existing fixed costs are referred to as "sunk" costs. In economic theory, sunk costs should not be considered when assessing future investments because they are incurred regardless of whether the future investment is undertaken.

Furthermore, the RIM test results can be misleading. For an efficiency program with a RIM benefit-cost ratio of less than one, the net benefits (in terms of PV$) will be negative. A negative net benefit implies that the investment will increase costs. However, as described above, the costs that drive the rate impacts under the RIM test are not new incremental costs associated with efficiency resources. They are existing costs that are already in current electricity or gas rates. Any rate increase caused by lost revenues would be a result of recovering those existing fixed costs over fewer sales, not as a result of incurring new costs. However, efficiency planners frequently present their RIM test results as negative net benefits, implying that the efficiency resource will increase costs, when in fact it will not.

Finally, all electricity and gas resources can result in some form of cross-subsidy. Applying the RIM test to EE resources is inconsistent with how other electricity and gas resources are evaluated for cost-effectiveness.

C.3 Rate Impacts and Customer Equity

In general, efficiency resources will result in lower average customer bills, despite any increase in rates.[53] Those customers that participate in an efficiency program will typically experience lower bills, while those that do not participate may experience higher rates and therefore higher bills.[54] Therefore, the rate impacts of EE resources are not a matter of cost-effectiveness. Instead, they are a matter of customer equity; between customers who participate in efficiency programs and those who do not.

Another limitation of the RIM test is that it does not provide the specific information that efficiency planners and regulators need to assess the equity impacts of efficiency resources. In order to understand equity impacts, it is necessary to simultaneously assess (a) the impacts of efficiency resources on long-term average rates; (b) the impacts of efficiency resources on long-term average customer bills; (c) and the extent to which customers participate in efficiency resource programs (over time) and thereby experience lower bills.

Put another way, regulators and other policymakers need to be able to compare the magnitude of bill reductions to the participating customers against the magnitude of any rate and (therefore) bill increases to non-participating customers and the portion of customers expected to experience such adverse effects. The RIM test does not provide this essential information. It only assesses whether rates will go up or not. It does not divulge the magnitude of the increase; nor does it indicate how many customers will experience the impact as an increase in their bills.

Some of the problems of the RIM test stem from the fact that it attempts to combine cost-effectiveness issues and equity issues into a single calculation. It combines the lost revenues (which are historical, unavoidable costs that drive equity issues) with the resource costs and benefits (which are future, avoidable costs that drive cost-effectiveness issues). By combining cost-effectiveness and equity issues into a single

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[53] This is not always the case. Many demand response programs can lead to reduced rates, because they involve very little lost revenue recovery. Some EE programs can lead to reduced rates, depending upon program costs, avoided costs, and lost revenue recovery.

[54] It is important to note that all customers experience some of the benefits of efficiency resources—regardless of whether they participate in the programs. In particular, efficiency resources can reduce the need for new generation capacity, reduce wholesale capacity prices, reduce wholesale energy prices, reduce T&D costs, improve system reliability, reduce risk, and more. All of these benefits accrue to all customers. Nonetheless, it is also generally true that efficiency participants will experience greater benefits than non-participants, due to the immediate reduction in their electricity bills.

calculation, the RIM test actually conflates the two issues and provides results that are not meaningful for either one.

The solution to this problem is to undertake two separate analyses. The cost-effectiveness analysis should account for all the future, avoidable costs and benefits, using the principles and concepts described in this manual. A separate rate impact and equity analysis can be used to assess the distributional impacts of the EE resource (US OMB 2003, 14), by analyzing the likely long-term impact on rates, bills, and customer participation.

C.4 A Better Approach for Analyzing Rate Impacts

A thorough understanding of the implications of efficiency rate impacts requires analysis of three important factors: rate impacts, bill impacts, and participation impacts.

- **Rate impacts** provide an indication of the extent to which rates for all customers might increase due to efficiency resources.
- **Bill impacts** provide an indication of the extent to which customer bills might be reduced for those customers that install efficiency resources.
- **Participation impacts** provide an indication of the portion of customers will that will experience bill reductions or bill increases. Participating customers will generally experience bill reductions while non-participants might see rate increases leading to bill increases.

Taken together, these three factors indicate the extent to which customers as a whole will benefit from efficiency resources, and also the extent to which efficiency resources may lead to distributional equity concerns. It is critical to estimate the rate, bill and participant impacts properly, and to present them in terms that are meaningful for considering distributional equity issues (SEE Action 2011a).

Rate Impact Estimates

Rate impact estimates should account for all factors that impact rates. This would include all avoided costs that might exert downward pressure on rates, as well as any factors that might exert upward pressure on rates. Any estimates of the impact of lost revenue recovery on rates should (a) only reflect collection of lost revenues necessary to recover fixed costs, and (b) only reflect the actual impact on rates according the jurisdiction's ratemaking practices.

Rate impacts should be estimated over the long term, to capture the full period of time over which the efficiency savings will occur. The study period should include all of the years in which efficiency resources are implemented, plus enough years to include the full measure lives of the last efficiency resources installed. This is necessary to capture the full effect of the downward pressure on rates from avoided generation, transmission, and distribution costs.

Rate impacts should also be put into terms that place them in a meaningful context, so that they can be properly considered and weighed by efficiency planners and regulators. For example, they should be put in terms of ¢/kWh impacts, dollars per month, percent of total rates, or percent of total bill.

Rate impacts can be markedly different across different customer types. Therefore, it may be necessary to analyze the rate impacts for different customer sectors. Conducting a rate impact analysis for every customer class is probably too burdensome and not necessary. Instead, analyses can be conducted for key customer types such as residential, small commercial, and large commercial and industrial.

Bill Impact Estimates

Bill impact estimates should build upon the estimates of rate impacts. While rate impacts apply to every customer within a rate class, bill impacts will vary between participants and non-participants. Further, bill impacts will vary depending upon the type of efficiency program and the amount of efficiency savings from the program. For these reasons, it may be appropriate to estimate bill impacts by efficiency program, or at least the key efficiency programs.

As with rate impacts, bill impacts should be estimated over the long term, to capture the full period of time over which the efficiency savings will occur. The study period should include all of the years in which efficiency resources are implemented, plus enough years to include the full measure lives of the last efficiency resources installed. This is necessary to capture the full effect of the downward pressure on bills from avoided generation, transmission, distribution, and other costs collectively born by ratepayers.

As with rate impacts, bill impacts should also be put into terms that place them in a meaningful context, so that they can be properly considered and weighed by efficiency planners and regulators. For example, they should be put in terms of dollars per month or percent of total bill.

Participation Estimates

Participation estimates should be put in terms of participation rates, measured by dividing efficiency program participants by the total population of customers eligible for the program. Participation rates provide context and more meaningful information relative to a simple number of program participants. Participation rates can also be used to compare participation across programs, across utilities, and across jurisdictions.

Participation rates should be estimated for each year of efficiency resource implementation. They should be compared across several years to indicate the extent to which customers are participating in the programs over time. Participation in multiple programs and across multiple years should be accounted for, and the impacts of participation in multiple efficiency programs by the same customer should be accounted for to the extent possible.

If program participation information is not currently available, it should be collected as soon as possible, so that meaningful estimates can be developed in future years. This type of information is critical for assessing the customer equity issues, and hence the rate impact issues, of efficiency resources.

Many equity concerns driven by rate impacts can be mitigated or even eliminated by promoting widespread customer participation in efficiency programs. Program participation information can be used to ensure that most, and potentially all, customers eventually install efficiency resources of one form or another, and thereby experience net lower bills. Efficiency program administrators could be charged with the responsibility to identify those customers that do not install efficiency resources, and to find ways to reach those customers that have not yet implemented some form of efficiency measure.

C.5 Relationship to the Cost-Effectiveness Analysis

The efficiency resource assessment described in Chapter 3 should provide a comparison of the costs and benefits of certain EE resources. The rate and bill impact analysis should provide an indication of the rate, bill, participation, and equity impacts of those efficiency resources.

Regulators and efficiency planners may wish to consider both analyses to determine whether to invest ratepayer funds in those efficiency resources. This determination could include a qualitative comparison of the trade-offs between cost-effectiveness and rate impacts. For example, regulators and efficiency planners could assess whether any expected long-term rate impacts are warranted in light of the cost-effectiveness results, the bill reductions, and the participation rates.

There is no bright line to determine how to balance these different impacts. Instead, this balance will need to be drawn by efficiency planners, ultimately with guidance and final approval of regulators.

Regulators and efficiency planners may choose to modify proposed efficiency programs or portfolios in order to strike a better balance between cost-effectiveness and equity issues. As noted above, one option would be to expand efficiency programs to include more participants and mitigate equity concerns. Another option would be to shift priority from programs that have low participation rates to those that have higher participation rates.

Utilizing Rate, Bill, and Participant Information

A recent study in Vermont estimated that an aggressive, long-term efficiency strategy would produce an average 7 percent reduction in electric bills (net of rate increases) for the more than 95 percent of residential customers who would be expected to participate in programs. The corresponding average increase in bills would be 4–5 percent for the fewer than 5 percent of customers who would not participate (VT DPS 2014).

The Vermont Public Service Board concluded that the estimated rate impact on that portion of customers was acceptable in light of the reduction in bills for participants and the other benefits of EE (VT PSB 2014).

Decision-makers in different jurisdictions might reach different conclusions regarding whether that trade-off would be worth making. However, they cannot make informed decisions unless they see data in this way.

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Exhibit 1, Page 6 of 6

EXHIBIT 2

HAS BEEN DEEMED

CONFIDENTIAL

IN ITS ENTIRETY

Chapter 10 - Appendix A

Preferred Plan Selection Scorecard[1]

Planning Objectives, Weights and Measures						
Category	Environmental/ Renewable/ Resource Diversity	Financial/ Regulatory	Customer Satisfaction	Economic Development	Cost	Overall Assessment
Category Weight	20%	20%	20%	10%	30%	100%
Plan	Resource Diversity	PV Free Cash Flow	Rate Increases	Net Job Growth (FTE-years)	PVRR	
R - RAP-35% CO2 Reduction	2	5	5	4	5	4.30
A - RAP	1	5	4	4	5	3.90
P - Meramec Retired 2020	1	5	4	4	5	3.90
Q - RES Compliance only	1	5	4	4	5	3.90
B - RAP EE only	1	5	3	3	5	3.60
M - Rush Island Retired 2024	3	4	3	4	4	3.60
N - Labadie Retired 2024	4	3	3	4	4	3.60
O - Meramec 2020-Labadie 2024	4	3	3	4	4	3.60
D - MAP	1	4	2	5	5	3.40
E - MAP EE only	1	4	1	3	5	3.00
F - MAP DR only	1	5	4	1	3	3.00
C - RAP DR only	1	5	4	1	2	2.70
L - No DSM-Solar	1	4	4	1	2	2.50
K - No DSM-Wind&SC	2	3	3	2	2	2.40
G - No DSM-CC	2	3	3	1	2	2.30
I - No DSM-Pumped Storage	2	3	3	1	2	2.30
H - No DSM-SC	1	3	3	1	2	2.10
J - No DSM-Nuclear	2	1	1	3	1	1.40

Scoring Guide	
Significant Advantage	5
Moderate Advantage	4
No Advantage or Disadvantage	3
Moderate Disadvantage	2
Significant Disadvantage	1

Overall Assessment Guide	
Top-tier Plan	
Mid-tier Plan	
Bottom-tier Plan	

Notes on Scores by Policy Objective	
Environmental/Diversity	Inclusion of MAP or RAP energy efficiency; new nuclear; combined cycle; significant early coal retirement; additional wind, solar or pumped hydro were viewed as advantageous.
Financial Regulatory	Financial and regulatory risks associated with new nuclear; significant early coal retirement; cessation of energy efficiency programs; and/or implementation of overly aggressive energy efficiency programs were viewed as disadvantageous, as were large negative impacts on cash flow.
Customer Satisfaction	Lower levelized annual rate increases, inclusion of energy efficiency and demand response, inclusion of additional new zero carbon resources, and reductions in coal-fired emissions were viewed as advantageous.
Economic Development	Plans were rated on a relative scale based on direct jobs (FTE-years) including both construction and operation.
Cost (PVRR)	Plans were rated on a relative scale based on present value of revenue requirements (PVRR).

Key to Abbreviations		
EE Only = Energy Efficiency Only, No Demand Response	CC = Combined Cycle Gas Turbine Generator	DR Only = Demand Response Only, No Energy Efficiency
RAP = Realistic Achievable Potential DSM Portfolio	MAP = Maximum Achievable Potential DSM Port	MEEIA = Missouri Energy Efficiency Investment Act Cycle 1
	RES = Renewable Energy Standard	SC = Simple Cycle Gas Turbine Generator

[1] 4 CSR 240-22.010(2)(C); 4 CSR 240-22.010(2)(C)1 through 3; 4 CSR 240-22.070(1); 4 CSR 240-22.070(1) (A) through (D)

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Exhibit 3

Nameplate MW

	Plans 2 - 7	Plan 2	Plan 2B	Plan 3	Plan 4	Plan 2D *	Plan 2BD *	Plan 4D *	Plan 2DEE **	Plan 2BDEE **	Plan 4DEE **
	Common Loss of Load, Plant Upgrades and Retirements	Early Asbury Retire Central Scale Renewables	Early Asbury Retire Central Scale Renewables - All 2023 Solar	Early Asbury Retire Central Scale Thermal	Early Asbury Retire Distributed Renewable	Early Asbury Retire - Central Scale Renewables Starting 2027	Early Asbury Retire - Central Scale Renewables All 2027 Solar	Early Asbury Retire - Distributed Renewables Starting 2027	Early Asbury Retire - Central Scale Renewables Starting 2028	Early Asbury Retire - Central Scale Renewables All 2028 Solar	Early Asbury Retire - Distributed Renewables Starting 2028
		RAP	RAP	RAP	RAP	RAP	RAP	RAP	RAP +	RAP +	RAP +
2020	Retire 200 MW Asbury										
2021	50 MW Wholesale Load Reduction										
2022	35 MW Upgrade to Stateline CC				19.5 MW Distributed Solar + Storage						
2023		50 MW Utility Solar	150 MW Utility Solar		50 MW Utility Solar						
2024											
2025											
2026	End of 150 MW Elk River PPA										
2027	Retire 162 MW at Energy Center	50 MW Utility Solar; 50 MW Utility Solar + Storage	50 MW Utility Solar + Storage	98 MW Aero derivative	50 MW Utility Solar + Storage	100 MW Utility Solar; 50 MW Utility Solar + Storage	150 MW Utility Scale + 50 MW Utility Solar + Storage	19.5 MW Distributed Solar + Storage, 50 MW Utility Solar + 50 MW Utility Solar + Storage			
2028					19.5 MW Distributed Solar + Storage			19.5 MW Distributed Solar + Storage	100 MW Utility Solar; 50 MW Utility Solar + Storage	150 MW Utility Scale + 50 MW Utility Solar + Storage	39 MW Distributed Solar + Storage, 50 MW Utility Solar + 50 MW Utility Solar + Storage
2029	End of 105 MW Meridian Way PPA	50 MW Utility Solar				50 MW Utility Solar			50 MW Utility Solar		
2030											
2031											
2032					13.5 MW Distributed Solar + Storage			13.5 MW Distributed Solar + Storage			13.5 MW Distributed Solar + Storage
2033											
2034	Retire 28 MW at Riverton CT	50 MW Utility Solar + Storage	50 MW Utility Solar + Storage	49 MW Aero derivative	50 MW Utility Solar	50 MW Utility Solar + Storage	50 MW Utility Solar + Storage	50 MW Utility Solar	50 MW Utility Solar + Storage	50 MW Utility Solar + Storage	50 MW Utility Solar
2035											
2036					13.5 MW Distributed Solar + Storage			13.5 MW Distributed Solar + Storage			13.5 MW Distributed Solar + Storage
2037											
2038											

* Delay all new renewable resources to 2027

** Delay all new renewable resources to 2028 and enhanced RAP Implemented 2021

Summer Accredited MW

	Plans 2 - 7	Plan 2	Plan 2B	Plan 3	Plan 4	Plan 2D *	Plan 2BD *	Plan 4D *	Plan 2DEE **	Plan 2BDEE **	Plan 4DEE **
	Common Loss of Load, Plant Upgrades and Retirements	Early Asbury Retire Central Scale Renewables	Early Asbury Retire Central Scale Renewables - All 2023 Solar	Early Asbury Retire Central Scale Thermal	Early Asbury Retire Distributed Renewable	Early Asbury Retire - Central Scale Renewables Starting 2027	Early Asbury Retire - Central Scale Renewables All 2027 Solar	Early Asbury Retire - Distributed Renewables Starting 2027	Early Asbury Retire - Central Scale Renewables Starting 2028	Early Asbury Retire - Central Scale Renewables All 2028 Solar	Early Asbury Retire - Distributed Renewables Starting 2028
		RAP	RAP	RAP	RAP	RAP	RAP	RAP	RAP +	RAP +	RAP +
2020	Retire 200 MW Asbury										
2021	50 MW Wholesale Load Reduction										
2022	35 MW Upgrade to Stateline CC				13 MW Distributed Solar + Storage						
2023		25 MW Utility Solar	75 MW Utility Solar		25 MW Utility Solar						
2024											
2025											
2026	End of 150 MW Elk River PPA										
2027	Retire 162 MW at Energy Center	25 MW Utility Solar; 30 MW Utility Solar + Storage	30 MW Utility Solar + Storage	98 MW Aero derivative	30 MW Utility Solar + Storage	50 MW Utility Solar; 30 MW Utility Solar + Storage	75 MW Utility Scale + 30 MW Utility Solar + Storage	13 MW Distributed Solar + Storage, 25 MW Utility Solar + 30 MW Utility Solar + Storage			
2028					13 MW Distributed Solar + Storage				50 MW Utility Solar; 30 MW Utility Solar + Storage	75 MW Utility Scale + 30 MW Utility Solar + Storage	26 MW Distributed Solar + Storage, 25 MW Utility Solar + 30 MW Utility Solar + Storage
2029	End of 105 MW Meridian Way PPA	25 MW Utility Solar				25 MW Utility Solar			25 MW Utility Solar		
2030											
2031											
2032					9 MW Distributed Solar + Storage			9 MW Distributed Solar + Storage			9 MW Distributed Solar + Storage
2033											
2034	Retire 28 MW at Riverton CT	30 MW Utility Solar + Storage	30 MW Utility Solar + Storage	49 MW Aero derivative	25 MW Utility Solar	30 MW Utility Solar + Storage	30 MW Utility Solar + Storage	25 MW Utility Solar	30 MW Utility Solar + Storage	30 MW Utility Solar + Storage	25 MW Utility Solar
2035											
2036					9 MW Distributed Solar + Storage			9 MW Distributed Solar + Storage			9 MW Distributed Solar + Storage
2037											
2038											

* Delay all new renewable resources to 2027

** Delay all new renewable resources to 2028 and enhanced RAP implemented 2021

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's 2019 Triennial Compliance Filing Pursuant to 4 CSR 240-22	)))	**File No. EO-2019-0049**

AFFIDAVIT OF BRAD J. FORTSON

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

Subscribed and sworn to be this 28th day of February. 2020.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2023
Commission Number: 15207377

Dianna L. Vaught
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's 2019 Triennial Compliance Filing Pursuant to 4 CSR 240-22	)))	**File No. EO-2019-0049**

AFFIDAVIT OF JORDAN HULL

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, Jordan Jull, 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.

Jordan Hull

Subscribed and sworn to be this 28th day of February. 2020.

Dianna L. Vaught
Notary Public

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2023
Commission Number: 15207377

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's 2019 Triennial Compliance Filing Pursuant to 4 CSR 240-22	)))	**File No. EO-2019-0049**

AFFIDAVIT OF KRISHNA POUDEL

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, Krishna Poudel, 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.

Krishna Poudel

Subscribed and sworn to be this 29th day of February. 2020.

Dianna L. Vaught
Notary Public

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2023
Commission Number: 15207377