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Before the State Corporation Commission
of the State of Kansas

Direct Testimony

of

James McMahon

on behalf of

The Empire District Electric Company

May 27, 2021

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THE EMPIRE DISTRICT ELECTRIC COMPANY
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I. INTRODUCTION

Q. Please state your name, employer, and title.

A. My name is James McMahon. I am a Vice President at Charles River Associates ("CRA") in the energy practice.

Q. Please describe CRA and your duties.

A. CRA is a consulting firm that offers economic, financial, and strategic expertise to support our clients in business decisions, regulatory and litigation proceedings, and market and policy analysis. CRA's energy practice advises electric utilities, power developers, investors, and other energy market participants in the areas of strategy, market analysis and forecasting, asset transactions and valuation, resource planning, and regulatory support and compliance. I specialize in corporate strategy, business planning, and transaction support and have advised energy executives across the U.S. I currently lead the advisory services area for CRA's energy practice and oversee many of CRA's projects and client relationships in the electric utility sector, working on a broad range of topics related to resource planning, market price forecasting, and electric rate analysis.

Q. How long have you been in your role at CRA, and what positions did you hold previously?

A. I have been in my current role at CRA since 2014, and I have more than twenty years of experience in energy consulting with CRA and other firms. A copy of my resume is attached to my testimony as **Schedule JM-1**.

Q. Please briefly describe your education.

A. I hold a JD and MBA from the College of William and Mary and a BA in Economics from Tufts University.

Q. Describe your experience with integrated resources planning and utility power market analysis.

A. CRA, as a company, and the individuals supporting the present assessment, have extensive experience in Integrated Resource Planning ("IRP") and utility power market analysis. I personally have led, managed and worked on numerous IRPs and power market analyses for investor-owned and publicly-owned utilities in my career. This work has been performed on behalf of utilities located across the U.S. representing diverse portfolios of resources. My work has involved scenario development, portfolio modeling and analysis, tradeoff analysis, and stakeholder support, among other things.

CRA and teams that I have led have conducted and supported IRPs and related resource planning efforts for numerous utilities in the past five years, in addition to Empire:

- For Northern Indiana Public Service Company ("NIPSCO"), an Indiana utility owned by NiSource, my team led the 2018 IRP and is currently leading the company's 2021 IRP.
- For Alliant Energy, my team led a resource planning initiative for the company's two utilities, Wisconsin Power and Light and Interstate Power and Light (located in Iowa), in 2019 and 2020.
- For Hoosier Energy, an Indiana generation and transmission cooperative, my team led a resource planning initiative in 2019 and 2020.

- For Great River Energy, a Minnesota and North Dakota generation and transmission cooperative, my team led a resource planning initiative in 2019 and 2020.
- For Black Hills Energy, my team supported the company's Wyoming IRP in 2018 and 2019.
- For American Electric Power, my team is currently engaged to lead two of the company's IRPs in Oklahoma and Arkansas.
- For Dominion Energy, my team was hired by the utility to review the company's South Carolina utility's resource planning approach and methodologies and to lead a stakeholder process, both of which are ongoing.

While our role on a resource planning project is based on the needs of the client, in many cases (including those described above) we perform end-to-end services, which can include price forecasting, assumptions development, scenario analysis, market and portfolio modeling, stakeholder engagement, report development, and testimony development (as appropriate).

II. OVERVIEW OF TESTIMONY

Q. Please describe the purpose of your Direct Testimony in this proceeding.

A. I am testifying on behalf of The Empire District Electric Company ("Empire"). My testimony reviews Empire's Generation Fleet Savings Analysis ("GFSA") and also addresses Empire's 2016 Integrated Resource Plan (the "2016 IRP") and Empire's 2019 Integrated Resource Plan (the "2019 IRP"). I explain Empire's IRP analyses and review the approach, modeling tools, methodology, assumptions, and results of the GFSA. I also identify the savings to customers relating to the retirement of the Asbury coal plant

("Asbury") based upon the GFSA. Those customer savings are after accounting for those customers continuing to pay the pre-tax return on the remaining investment in Asbury. Finally, I discuss why Empire's decision to acquire 600 MW of wind when it already had adequate capacity and energy resources capable of meeting customer demand was reasonable.

If the Commission will recall, I previously submitted pre-filed testimony on October 31, 2017 in Kansas Corporate Commission Docket No. 18-EPDE-184-PRE in support of Empire's GFSA and the differences between the GFSA and Empire's 2016 IRP.

Q. Please explain the GFSA – Empire's Generation Fleet Savings Analysis – and your role in its development.

A. Empire conducted the GFSA to update its 2016 IRP with new assumptions on wind cost and performance parameters and a new methodology to account for the Southwest Power Pool ("SPP") Integrated Marketplace ("IM"). A copy of the GFSA is attached to my testimony as **Confidential <u>Schedule JM-2</u>.** The analysis includes a thorough assessment of the potential resource plans available to Empire using the full suite of models that are deployed during a normal IRP process. The GFSA calculates a net present value of future revenue requirements across a range of potential plans for Empire and identifies a lower cost approach for customers. My colleagues and I at CRA reviewed various elements of the analysis and advised Empire staff as it was conducted. CRA provided input on assumptions development, portfolio creation, and uncertainty analysis and also reviewed detailed results to check outputs and synthesize key findings. My colleagues and I also assessed the reasonableness of the approach and assumptions based on our experience with utility resource planning tools, processes, and current trends in the electricity markets.

Q. Why was the GFSA developed?

A. As explained in Empire witness Shaen Rooney's testimony, as part of the ongoing obligation to review its resource acquisition strategy in the context of its IRP requirements, Empire, in conjunction with its parent company, Algonquin Power & Utilities Corp., ("APUC") identified a potential opportunity to leverage its experience in developing renewable projects in concert with tax equity partners. As a result, Empire launched a new study to assess the impacts of adding wind to its portfolio prior to the expiration of federal production tax credits ("PTCs"), using the 2016 IRP as a baseline, but updating several key assumptions to reflect market, policy, technology, and regulatory trends.

Q. Describe the general process for the development of the GFSA.

A. Empire updated several modeling inputs and assumptions and engaged ABB Enterprise Software Inc. ("ABB") to perform a full quantitative analysis of its options, leveraging the models that were used in the 2016 IRP. Empire then engaged CRA to review and provide comments on the input assumptions, modeling approach, and draft results prior to authorizing ABB's final modeling runs. Empire then used ABB's analysis results and outputs to develop a report, which is referred to as the GFSA.

Q. Please further describe ABB's role in the process.

A. ABB was commissioned by Empire to perform the market, portfolio, and financial modeling that ultimately drives the calculation of Empire's revenue requirement in the GFSA analysis. At that time, ABB had worked with Empire for more than ten years in this capacity to develop market forecasts and support IRP analysis.

Q. Describe the approach used by ABB to model the Empire portfolio, identify optimal resource options, and estimate the revenue requirement impact.

A. ABB's analysis approach can be summarized in three major steps. First, macro-level market forecasts for commodities like natural gas prices, coal prices, carbon prices, and power prices are developed as part of a regular forecasting process that broadly assesses energy markets across the U.S. Second, ABB uses these market inputs and other details on Empire's existing portfolio and future portfolio options to develop a set of potential "plans" for Empire to pursue. Third, ABB evaluates each of those plans in a detailed modeling framework that performs plant dispatch and financial analysis to arrive at a revenue requirement estimate of Empire's portfolio over the long-term.

Q. Describe your experience with IRP models like those used in Empire's 2016 and 2019 IRPs and the GFSA.

A. CRA runs an integrated set of market models in support of its IRP and power markets analysis projects. These models simulate the evolution and operation of the power and fuels markets. Key aspects of power market simulation include capacity expansion, price formation, and plant-level dispatch. CRA's fuels models produce coal, oil, and gas price forecasts that are inputs to power market simulations. CRA also runs a utility financial model that produces a net present value revenue requirement based on information from power market simulations and other inputs.

Although not the same models as those used by ABB in the GFSA, the models CRA relies upon perform a similar function to ABB's Capacity Expansion Module and its Strategic Planning Module. Moreover, CRA has previously reviewed the inputs, outputs, and the methodologies used in ABB's models on behalf of other clients. CRA is generally knowledgeable on how these models function and how they were used to evaluate Empire's portfolio and produce the analysis.

III. SUMMARY OF MAIN CONCLUSIONS OF THE GFSA

Q. Please summarize the primary findings of the GFSA.

A. The analysis found that the lowest cost way for Empire to serve its load obligations over the next twenty to thirty years was to undertake a near-term strategy that builds up to 800 MW of strategically located wind in or near Empire's service territory and retires Asbury.[1]

Q. How are these conclusions in the GFSA different that those reached in the 2016 IRP?

A. The 2016 IRP concluded that it was most cost-effective to continue operating Asbury and to only acquire additional wind when current power purchase agreements expire in the late 2020s. Therefore, the 2016 IRP did not recommend near-term action around new builds or retirements.

Q. What are the major drivers of differences in the findings of the GFSA and the 2016 IRP?

A. Several changes in methodology and assumptions were made between the two studies, with three major changes driving the different findings. First, the GFSA analysis updated the assumptions for wind capital costs, reflecting recent declines in these costs and the ability for Empire to work with tax equity partners. Second, the GFSA analysis updated the capacity factor expectations for new wind plants, reflecting recent technology improvements and observed performance of operating plants. Third, the GFSA analysis modeled the SPP IM, reducing restrictions on the amount of wind that could be built by Empire and the availability of energy sales to the market, as well as incorporating nodal

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[1] The modeling assessment assumed for the GFSA had Asbury retiring at the end of 2018. Asbury was retired March 1, 2020. Details surrounding the retirement of Asbury are provided in the direct testimony of Empire witness Aaron Doll.

pricing detail. The assumption changes that were made between the 2016 IRP and the 2017 GFSA are discussed in detail below.

Q. Did Empire determine, based on the GFSA, that the preferred plan in its 2016 IRP was no longer appropriate?

A. Yes. On October 17, 2018, Empire filed with the Missouri Public Service Commission ("MPSC") its Notice of Change in Preferred Plan (Case No. EO-2019-0106). While the preferred plan in the 2016 IRP did not call for the addition of wind until 2029, the new preferred plan (the "2018 Updated Preferred Plan") called for up to 600 MW of wind to be added by the end of 2020. A report containing a description of all changes to the 2016 IRP preferred plan, the impact of each change on the present value of the revenue requirement and all other performance measures specified in the last filing, and the rationale for each change was attached to the Notice of Change in Preferred Plan and is attached to my testimony as **Confidential <u>Schedule JM-3</u>.**

Q. Does Empire's 2019 IRP build upon or contradict the findings and conclusions of the GFSA?

A. The preferred plan in Empire's 2019 IRP, which was provided to the MPSC on June 28, 2019, maintains consistency with and builds upon the 2018 Updated Preferred Plan. Like the 2018 Updated Preferred Plan, the 2019 IRP preferred plan incorporates 600 MW of new renewable wind generation as a core part of a reconfigured generation portfolio. The 2019 IRP preferred plan also proposes the retirement of Asbury. A copy of the 2019 IRP is attached to my testimony as **Confidential <u>Schedule JM-4</u>**.

IV. REASONABLENESS OF GFSA ASSUMPTIONS AND METHODOLOGY

Q. Are the updated assumptions for the GFSA and the associated conclusions reasonable, based on your review of the analysis and your experience in the utility industry?

A: Yes, the updates to the methodology and assumptions reflected then-current market conditions and were reasonable for conducting this analysis. I also believe that the conclusions presented in the GFSA are reasonable based on the input assumptions and the modeling approach that was deployed.

Q. Describe the details of the analytical tools used in the GFSA and how they support compliance with the requirements of state level IRP regulations.

A. ABB used two major models in the development of the analysis for the GFSA. The first is known as the Capacity Expansion Module ("CEM"), which effectively develops a set of portfolios or plans for the Empire system for further study. The CEM solves for the least cost combination of supply side and demand side resources, while satisfying a number of constraints like the minimum reserve margin level and maximum output. The CEM minimizes the present value of revenue requirements ("PVRR") and can be deployed under different market assumptions, including fuel prices, power prices, and carbon prices, in order to evaluate different least cost portfolios under various potential states-of-the-world.

The second model is known as the Strategic Planning Module, which performs both a full dispatch simulation of each portfolio and financial accounting in order to estimate Empire's revenue requirement for each plan considered. The Strategic Planning Module models the Empire fleet dispatch based on a set of market inputs for fuel, emissions, and power prices in chronological fashion. The model calculates market sales and purchases transactions with the SPP market. It combines the results of the variable cost dispatch analysis with a full financial analysis that incorporates all capital and fixed expenses, including calculations related to return on equity, cost of debt, asset depreciation, and taxes.

The use of both models is consistent with the MPSC's rules for resource planning, as they "consider and analyze demand-side resources, renewable energy, and supply-side resources on an equivalent basis," they "use minimization of the present worth of long-run utility costs as the primary selection criteria," and are designed to assess the "risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans." *See* Missouri Rule 20 CSR 4240-22.010. Although there are no similar IRP regulations in Kansas, Empire does informally provide the Kansas Corporation Commission Staff ("Staff") the executive summary of its Missouri IRP filings and meets annually with the Staff to discuss its generation fleet and fuel costs and its IRP filings. The use of these models is also consistent with the requirements of the Arkansas Public Service Commission and the Oklahoma Corporation Commission.

Q. Was it reasonable to start with the 2016 IRP instead of conducting a new IRP process for the GFSA?

A. Yes, the 2016 IRP was recently completed and contained all core data associated with Empire's base portfolio used to calculate the revenue requirement. Therefore, the 2016 IRP served as a reasonable comparison point against which to update several important assumption changes. The preferred plan in Empire's 2016 IRP was also a reasonable benchmark against which to evaluate different potential plans that build additional wind and retire Asbury.

Q. Why was it reasonable and necessary to update the modeling framework to include fuller treatment of the SPP IM, inclusive of nodal pricing basis?

A. SPP launched its IM in 2014, introducing a two-settlement system with a day-ahead market and a new real-time balancing market, under a locational marginal pricing framework.[2] The market reforms also combined all previous balancing authorities into one SPP Balancing Authority responsible for centralized dispatch. This means that all resources are dispatched across the pool in an economic fashion, rather than by individual balancing areas that prioritize serving local load. Pricing across the system is reflective of the marginal cost of production as well as transmission congestion and line losses, introducing different pricing between locations where Empire buys power from the grid to serve load and where it injects power into the grid at its various generating facilities.

From a modeling perspective, these market reforms have two major implications. The first is that all generation is dispatched against the market price, meaning that limitations on imported or exported power into and out of the Empire system are based on economic signals rather than physical capacity limits. Previously, the modeling enforced import and export constraints on the Empire balancing area. The second is that each generator will have a location-specific price against which it is dispatched and at which it is paid. Previously, the modeling assumed a single zonal price for all generators and load. When the GFSA was launched, over three years of historical nodal data had become available, allowing for a much richer dataset than the roughly one year of data available

[2] Locational marginal prices ("LMP") refer to the marginal clearing prices for electricity at various points or nodes throughout the SPP market. Pricing at these points is determined by the marginal costs of energy, congestion, and losses, resulting in different pricing throughout the system that is dependent on local supply, demand, and transmission infrastructure.

when IRP assumptions were being developed in 2015 for the 2016 IRP. Therefore, it was important for Empire and ABB to incorporate this historical price information in the assessment, and dispatch each generator to a specific nodal price.

Q. How did the ABB analysis for the GFSA evaluate risk and uncertainty?

A. ABB used the Strategic Planning Risk Module to develop risk profiles for each plan under evaluation. The risk profiles are based on weighting the likelihood of occurrence of different outcomes across critical uncertain factors. A decision tree was created to represent each possible outcome or pathway across a set of the uncertain factors that were defined by Empire, including load, fuel prices, power prices, carbon prices, capital costs, and nodal basis congestion. Each of the pathways was assigned a probability, and a weighted average calculation was performed across all outcomes to calculate an expected value of the revenue requirement. This approach also allows for comparisons under different input assumptions.

Q. Is this methodology reasonable and consistent with IRP regulatory requirements?

A. Yes, the Missouri IRP rules require that the utility assign a probability to each identified critical uncertain factor, then calculate the "expected performance and the risks of each alternative resource plan." Missouri Rule 20 CSR 4240-22.060. ABB's analysis approach for the GFSA is consistent with these requirements. As noted earlier, it is my understanding that since Kansas does not have IRP regulatory requirements, Empire has informally provided the Staff with information regarding its Missouri IRP filings.

Q. In conducting its GFSA, did Empire consider generation/supply, transmission, and demand response alternatives or options that might be reasonably available to the utility?

A. Yes, the GFSA started with the 2016 IRP, which conducted a full review of all options that might be reasonably available to Empire. Empire relied upon the 10-year load forecast developed in the 2016 IRP process and evaluated resource options necessary to meet expected peak load plus a reserve margin. The updated analysis for the GFSA changed certain assumptions, but still evaluated a broad suite of options.

Q. Describe the supply, transmission, and demand response alternatives or options that Empire determined were reasonably available at the time.

A. An extensive list of supply-side generation resources and market opportunities were evaluated in the 2016 IRP and in the GFSA. The resource alternatives included: coal plants, including options with carbon capture and sequestration; natural gas plants, including frame and aero-derivative turbines, combined cycles, and reciprocating engines; nuclear plants; wind plants, in different locations and under different ownership and contract structures; biomass plants; landfill gas plants; solar plants; distributed generation options, including small turbines and combined heat and power facilities; and battery storage facilities.[3]

As a member of SPP, Empire participates in the regional transmission planning process to assess transmission needs and the associated costs and timing of upgrades that reduce congestion, interconnect generation, facilitate market transactions, and otherwise maintain a viable transmission regional network. Empire's IRP provided detail on this process, including the identification of potential projects under consideration by SPP in

[3] Capital Cost Assumptions, Supply Side Alternatives Table tab of Empire's 2016 IRP.

Empire's service territory, and also summarized the status of Empire's specific transmission and distribution projects.

As part of the 2016 IRP, Empire engaged Applied Energy Group to conduct a Demand Side Management ("DSM") Potential Study that evaluated market segments in Empire's service territory, characterized potential demand side resources, estimated technical, economic, and achievable potential of these resources, and developed program-level potential estimates based on possible savings and associated costs. Several DSM futures were evaluated in the 2016 IRP, with varying levels of realistic and maximum achievable potential, along with an aggressive plan to meet future capacity needs. For the GFSA, one of these DSM options was incorporated in all portfolios, as discussed in more detail in the next section.

V. GFSA PORTFOLIO CONSTRUCTION

Q. Describe the specific details of the different portfolio plans that were analyzed in the GFSA.

A. Nine different plans or portfolios were identified as being least-cost plans under various assumptions using the CEM and analyzed in the GFSA. The table below summarizes the annual capacity additions for each plan.

Figure 1: Optimized Plans from Generation Fleet Savings Analysis[4]

	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6	Plan 7	Plan 8	Plan 9
YEAR	Plan 5 (2016 IRP)	Base - 850 MW Wind Limit	Base - 400 MW Low LCOE Wind Limit	Base with Asbury	High Fuel	Low Fuel	Base - 300 MW Low & Mid LCOE Wind Limit	Base - 200 MW Low & Mid LCOE Wind Limit	Base - 200 MW Low & Mid LCOE Wind Limit - No Solar
2018	Update Asbury	Retire Asbury	Retire Asbury	Update Asbury	Retire Asbury	Retire Asbury	Retire Asbury	Retire Asbury	Retire Asbury
2019		800 MW Low LCOE Wind	400 MW Low LCOE Wind	800 MW Low LCOE Wind	800 MW Low LCOE Wind	800 MW Low LCOE Wind	300 MW Low LCOE Wind	200 MW Low LCOE Wind	200 MW Low LCOE Wind
2020			400 MW Mid LCOE Wind		100 MW Solar		300 MW Mid LCOE Wind	200 MW Mid LCOE Wind	200 MW Mid LCOE Wind
2021				Retire EC1&2	100 MW Solar				
2022									
2023	Retire EC1	Retire EC1	Retire EC1		Retire EC1	Retire EC1	Retire EC1	100 MW CC Retire EC1	100 MW CC Retire EC1
2024									
2025		100 MW CC	100 MW CC		100 MW CC	100 MW CC	100 MW CC	50 MW Solar	
2026	Retire EC2	Retire EC2	Retire EC2		Retire EC2	Retire EC2	Retire EC2	100 MW Solar Retire EC2	100 MW CC Retire EC2
2027								100 MW CC	
2028							100 MW Solar		
2029	100 MW Wind 100 MW CC						100 MW Solar		
2030				100 MW Solar			100 MW CC		
2031	150 MW Wind	100 MW Solar	100 MW Solar	100 MW Solar				50 MW Solar	
2032		100 MW CC	100 MW CC		100 MW CC	100 MW CC			
2033	Retire Riv10&11	Retire Riv10&11	Retire Riv10&11	Retire Riv10&11	Retire Riv10&11	Retire Riv10&11	Retire Riv10&11	Retire Riv10&11	100 MW CC Retire Riv10&11
2034								100 MW CC	
2035	200 MW CC			167 MW Recip					
2036									
2037									

All plans include retirements at Energy Center 1 and 2 and Riverton 10 and 11, and include the same DSM programs. Plan 1 is the Preferred Plan from the 2016 IRP, but with the addition of DSM. Plan 2 was developed with the CEM with the new assumptions for the 2017 GFSA, allowing for Asbury to retire if economic. Plan 2 contains 800 MW of wind in 2019, retires Asbury in 2018, and adds solar and natural gas combined cycle units over time to meet reserve margin requirements. Plan 3 constrains the amount of low-levelized

[4] Confidential **Schedule JM-2**, p. 16.

cost of energy ("LCOE") wind in Plan 2 to 400 MW, and thus has 400 MW of low-LCOE wind and 400 MW of mid-LCOE wind. Plan 4 does not allow Asbury to retire until 2035. As a result, Plan 4 builds solar and natural gas combined cycles later than the other plans, but still builds 800 MW of wind in 2019.

Plan 5, developed with the CEM, assumes high market prices for gas and power and builds more solar in the early years than the other plans (200 MW by 2021), along with 800 MW of wind. Plan 6 was developed with low market prices for gas and power and builds 200 MW of natural gas-fired combined cycle capacity, along with 800 MW of wind, but does not build any solar. Plan 7 constrains the amount of wind of each type to 300 MW, and thus has 300 MW of low-LCOE wind and 300 MW of mid-LCOE wind. Plan 8 constrains the amount of wind of each type to 200 MW. Plan 9 uses the same inputs as Plan 8 but does not allow any solar builds. Thus, Plan 9 relies solely on new combined cycle capacity to meet future needs.

Q. How did Empire and ABB develop the set of different portfolio plans that were analyzed in the GFSA?

A. The plans were developed using the CEM with the same methodology used in the 2016 IRP, which allowed for economic retirements unless constrained otherwise (as in Plan 4). Core runs were performed for the base case market outlook, as well as under high and low market conditions to develop least cost portfolio plans under different potential states-of-the-world. Constraints on the amount and location of new wind developments were then applied to develop different plans that could assess the costs and risks of varying amounts of wind and different proportions of wind in mid-LCOE and low-LCOE regions. To assess the cost impacts of the potential decision to retire Asbury, a plan was developed that forced

Asbury to remain in service until its planned end of life. For comparison, the preferred plan from the 2016 IRP was included as an important benchmark.

Q. Why were the GFSA plans different than the plans developed in the 2016 IRP?

A. The different input assumptions result in different least cost plans. Most importantly, improved cost and capacity factor performance for wind resources and the removal of limits on the amount of energy Empire can sell to the market drove the CEM to select early wind additions as the least cost outcome across all of the scenarios. To stress test this outcome, constraining wind builds and forcing Asbury to continue operating were reasonable ways to develop alternative portfolio options.

Q. Please further describe the constraints or wind builds.

A. Empire constrained the amount of wind that could be built to prevent the model from building an unlimited amount of capacity that relies on market sales to offset upfront capital costs. In the past, Empire placed maximum capacity limits on wind based on minimum load levels to match low-variable cost resource output with the shape of Empire's native load. This was done in an attempt to match supply and demand during minimum load hours. This, in effect, would mitigate the amount of excess supply that the utility would have available during low-demand off-peak periods. However, with the implementation of the SPP IM, physical restrictions on off-peak energy production are no longer constraining, since all generation is sold into the wholesale market.

Nevertheless, relying solely on off-system sales to manage costs introduces risk, so Empire constrained the model to cap total nameplate wind capacity in the portfolio to a level roughly equivalent to peak load (the total wind capacity constraint includes existing contracted wind capacity plus the new additions). This reduces aggregate exposure to market sales and allows for different levels of new wind additions up to 845 MW[5] to be tested. Although wind resources are assumed to count for 15% capacity credit,[6] the constraint of up to 800 MW of new wind still allowed for these additions to replace a sizeable portion of the Asbury capacity, while delaying the need for future fossil-fired capacity builds.

VI. REASONABLENESS OF PORTFOLIO CONSTRUCTION ASSUMPTIONS

Q. Please explain in more detail the assumption changes that were made between the 2016 IRP and the 2017 GFSA?

A. Six notable assumption changes that influence the drivers described earlier were made between the 2016 IRP and the 2017 GFSA:

- First, the 2017 analysis assumed Empire has open access to the SPP market for energy sales and purchases and incorporated nodal pricing differences for each of the generators in the fleet. This was done in order to more accurately represent the SPP IM and because there is now enough nodal pricing data after three years of market operation to provide confidence in the nodal modeling.
- Second, the reasonable achievable potential ("RAP') portfolio of DSM measures, adopted in MPSC Case No. ER-2016-0023, was included in all portfolios.
- Third, updated market forecasts from ABB for natural gas, coal, and power prices were used.

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[5] Wind capacity was limited to 1,100 MW total. Since 255 MW of wind capacity already existed in the portfolio, 845 MW of new additions were allowed. Given wind block sizes of 50 MW, this effectively results in an 800 MW cap.

[6] Note that each wind farm in SPP is subject to a detailed coincident peak assessment to determine accredited capacity. It was expected, at the time, that new wind projects would receive approximately 15% credit.

- Fourth, updated assumptions for wind capital costs, including the cost impact of using tax equity partners and updated assumptions on wind capacity factor performance, were used.
- Fifth, carbon pricing was removed from the base case, to reflect updated views on federal policy.
- Sixth, operations and maintenance cost and ongoing capital expenditure estimates were updated to reflect Empire's latest internal budgets.

Q. Why was it reasonable and necessary to make these assumption changes?

A. The changes reflect the key developments in wholesale power market design, electric generating technology advancement, commodity market dynamics, and state and national regulatory policy that were witnessed over the one to two years following the completion of the 2016 IRP. The growing maturity of SPP's IM required a change to the modeling approach, while developments in wind technology and fuel and power markets required the most current views to be incorporated. Further, state regulatory stipulations in Missouri (Case No. ER-2016-0023) and a new federal administration driving change at the Environmental Protection Agency required updates to assumptions around DSM and carbon pricing, respectively.

Q. Please describe how ABB develops market assumptions.

A. ABB regularly develops a Reference Case set of market forecasts for natural gas, coal, emissions, and power market prices. These forecasts, along with scenario analyses, are developed through fundamental market assessments and modeling and are relied upon by many electric utilities, power project developers and investors in the power industry. The models incorporate key commodity price drivers and rely on economic analysis to produce internally consistent outlooks of the energy sector, with regional detail on fuel prices delivered to Empire's region and power prices across SPP. The Fall 2016 Reference Case forecasts were used for the GFSA. ABB's local natural gas price point for the Missouri region was used, along with the power price associated with the SPP-Kansas-Missouri region. Empire's known delivered coal prices were used during the duration of its existing coal contract terms and were grown over time according to the expected growth rates in delivered coal prices to the SPP-Kansas-Missouri region in ABB's Reference Case.

Q. How do the Fall 2016 ABB Reference Case assumptions compare with the assumptions used in Empire's 2016 IRP, and what were the reasons for any differences?

A. The natural gas and power market price forecasts used in the GFSA are lower than those used in the 2016 IRP, which were based on ABB's Spring 2015 Reference Case. The natural gas price forecast came down as a result of continued low-cost domestic production and increases in estimated reserves, which was reflected in lower market forwards. The power price forecast came down as a result of the assumption to remove the carbon price from the market and the lower gas price trajectory. The change in federal administration after the November 2016 election and the subsequent withdrawal of the Clean Power Plan made it reasonable to remove carbon pricing from the base case.

Q. How do ABB's natural gas price projections compare with other public forecasts?

A. ABB's natural gas price projections are generally consistent with other forecasts in the public domain and followed the same general downward trend described above. The U.S.

Energy Information Administration publishes an Annual Energy Outlook (AEO)[7] which presents a comprehensive review of energy markets along with fundamental forecasts of key drivers like natural gas prices. ABB's natural gas price projections that were used in the GFSA follow a similar trajectory as those from the AEO in both 2016 and 2017. The 2015 AEO projected significantly higher prices which were in line with those from ABB's Spring 2015 Reference Case, reflecting the fact that market dynamics drove the outlook down in subsequent years.

Q. Are the ABB market forecasts adjusted prior to being deployed in IRP models?

A. Yes, in a couple of instances. Delivered coal prices are dependent on specific contracts that are in place for individual plants. As a result, current contract pricing is used when it is known and then grown at the rate projected by ABB for delivered coal in the SPP-Kansas-Missouri region. Therefore, the general price trajectory is consistent with the rest of ABB's market forecasts, but customized to the actual prices seen by Empire's plants.

Secondly, Empire applies a nodal pricing basis to each of the plants in its portfolio to account for the differences in power prices between what Empire pays to serve its load and what it receives for its generators. This needs to be done to account for the fact that in SPP's IM, different prices are realized across the system. This is especially important when evaluating resources across a broad geography, because pricing dynamics differ according to the relative amount of supply and demand in the region, the type of supply resources that are present, and the local transmission infrastructure. Empire used historical nodal pricing data to apply an hourly basis to each generator to adjust ABB's SPP-Kansas-

[7] https://www.eia.gov/outlooks/aeo/

Missouri price forecast. The new wind options for the GFSA were assigned a basis based on three years of historical data from proxy locations. The mid-LCOE wind options used the Asbury nodal price basis, and the low-LCOE wind options used the existing Elk River wind nodal price basis.[8] Given that, at the time, specific sites for the new wind projects had not been identified, using data from the proxy locations was reasonable in order to approximate potential nodal price differences for projects in the general vicinity.

Q. Beyond the market inputs, what other assumptions are important to the conclusions reached in the GFSA?

A. The costs associated with building new resources and operating existing ones are very important to any resource planning exercise. Empire relied on a capital cost study produced by Burns and McDonnell for the 2016 IRP for new build costs and ongoing fixed operations and maintenance ("O&M") costs. Cost estimates for wind, solar, and certain natural gas engines were updated by Empire staff upon receipt of new information since the 2016 assumptions review was conducted and based on direct quotes from vendors. Fixed O&M costs and ongoing capital expenditure expectations for the existing fleet were developed internally by Empire staff, consistent with its budget and experience.

Q. What capital cost assumptions were used for the new wind options under the GFSA and under the 2016 IRP?

A. In the 2016 IRP, Empire assumed that new wind would cost $2050/kW ($2016). The GFSA assumed that new wind would cost $1,660/kW ($2016) in 2019 and $1,642/kW ($2016) in

[8] Elk River is an existing wind facility in Kansas, identified as an appropriate nodal proxy for low-LCOE wind options.

2020.[9] As a result of the expected partnership with tax equity investors, at the time, Empire was expected to only contribute 46.8% of the upfront capital costs for plants that would come online by 2020 for mid-LCOE projects and 40.4% for plants that would come online by 2020 for low-LCOE projects, since these projects could take advantage of the full production tax credit.[10] The lower percentage for low-LCOE projects reflects higher assumed production tax credits from higher plan capacity factors. Therefore, the net capital cost contribution for Empire for a mid-LCOE plant coming online in 2020 was $769/kW, while the net contribution for a low-LCOE plant coming online in 2019 was $671/kW. For comparison, for low-LCOE plants that would come online in 2022, the all-in capital cost was assumed to be $1,606/kW, while the Empire contribution was assumed to be 60.4% as a result of a lower production tax credit level. This results in direct capital cost expenditures of $970/kW.

The baseline all-in wind capital costs in the $1,600/kW to $1,700/kW range in the GSFA were reasonable and consistent with public sources and my experience with resource planning cost estimates. For example, the AEO in 2017 reported average wind capital costs of $1,686/kW.[11] Other commonly-sourced public reviews of wind capital costs performed by Lazard and the Lawrence Berkeley National Laboratory ("LBNL") estimated new wind build costs of $1,475/kW and $1,587/kW at the time.[12]

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[9] Work paper available upon request, Capital Cost Assumptions, Wind Capital Cost Assumptions tab.
[10] *Id.*
[11] Work paper available upon request, Wind Cost Estimates, tab Summary.
[12] *Id.*

Q. Were transmission interconnection costs also included in the GFSA analysis?

A. Yes. Empire also separately developed interconnection costs estimates and assumptions for additional transmission system upgrades that would likely be required for new projects. Costs in low-LCOE regions were assumed to be approximately $123/kW, while costs in mid-LCOE regions were assumed to be approximately $31/kW.[13]

Q. What was assumed for fixed operations and maintenance ("FOM") costs for new wind with the GFSA?

A. Empire assumed FOM costs of approximately $50/kW-yr for the new wind additions based on recent experience with wind projects. This estimate was reasonable and within the range of recent cost estimates in the public domain, including the AEO's estimate of $47/kW-yr, Lazard's estimate of $38/kW-yr, and LBNL's range of $27-55/kW-yr based on project surveys and data from a large wind operator.

Q. What capacity factor assumptions were made for the new wind builds?

A. For the GFSA, Empire developed capacity factor estimates based on historical meteorological data, turbine manufacturer performance data, industry assumptions, and actual operating data from the existing Elk River wind project. The annual capacity factor of new wind projects in mid-LCOE regions was assumed to be 46%, while the annual capacity factor of new low-LCOE projects was assumed to be 54%.[14]

Q. Did Empire confirm all of these input assumptions through a competitive solicitation process before new resources were acquired?

[13] Confidential **Schedule JM-2**, p. 33.
[14] *Id.* at 27, 28.

A. Yes. The competitive bid process is described in the direct testimony of Empire witness Shaen Rooney.

Q. Which input variables did Empire identify as critical uncertain factors for the GFSA, and how were they assessed in the risk analysis?

A. Empire identified three major variables as critical uncertain factors. The first was market power prices. In addition to the base case, Empire modeled ranges of both high and low power prices for the GFSA. The high and low power prices were accompanied with high coal and gas prices in the high case, and low gas and coal prices in the low case. Although technically different inputs to the modeling exercise, natural gas, coal and power prices are correlated and were treated together as an integrated critical uncertain factor. The second critical uncertain variable was nodal price basis, which is reflective of congestion on the transmission system throughout the SPP market. Similarly, base, high, and low case scenarios were developed. The third variable was carbon prices, and two distinct scenarios were developed: the base case, with no carbon price, and an alternative carbon price scenario, with a price on carbon starting in 2030. The risk analysis assessed all combinations of potential outcomes across these three uncertain factors, resulting in eighteen different permutations of market prices, nodal price basis, and carbon pricing.

Q. How and why was the treatment of critical uncertain factors for the GFSA different than in the 2016 IRP?

A. In the 2016 IRP, Empire identified four critical uncertain factors. Two of them were the same as those identified in the 2017 GFSA. They are market gas and power prices and carbon prices. The 2016 IRP also identified load growth and a variable which captured uncertainty in capital costs for generation and transmission projects and interest rates as critical uncertain factors. Capital cost uncertainty was less important for the GFSA. Although the capital costs of wind are a major driver of wind plan economics, all of the potential significant additions in the GFSA plans were near-term acquisitions where a level of price transparency already existed for Empire decision makers. Therefore, long-term uncertainty was less important. Similarly, long-term load uncertainty would have limited impact on the relative performance of the major plans, especially since open access to the SPP market to buy and sell energy, regardless of native load requirements, was available.

Nodal basis risk was introduced as a new critical uncertain factor, given the new modeling of the SPP IM and the locational price uncertainty that existed for generators as a result. This was especially true for wind plants which are often located far from load centers and subject to low price risk. Therefore, for the GFSA, it was important to test the impact of basis uncertainty over the expected operational lifetime of the new wind options.

Q. Are the ranges tested in the GFSA uncertainty analysis reasonable?

A. Yes. The ranges evaluated captured a reasonable band of upside and downside uncertainty for each of the critical uncertain factors. The high natural gas price trajectory generally follows the trajectory covered by the high range of natural gas prices in the 2017 AEO. The 2017 AEO low price trajectory generally stays between $3-4/MMBtu over the same time horizon, and current market forwards for the next few years remain below $3/MMBtu, suggesting that the low case evaluated in the GFSA covered a plausible downside reflective of then-current market sentiment and fundamental analysis.

The ranges used for the nodal basis also captured a reasonable band of potential outcomes. Given the potential for downside pricing risk, especially around wind plants, it was prudent to stress basis change that results in lower prices at the wind nodes, and Empire assumed 200% of the base case nodal discount in the high basis case. For example, for the low-LCOE wind options, the average annual nodal discount used in the base case is 0.865, meaning that prices at low-LCOE wind node were expected to be only 86.5% of the prices at which Empire would buy electricity to serve its native load. In the high basis case, this expands to 0.73 or 73%.[15] This level more than covered the recent discount that was observed in 2017.[16] It also assumed a persistent discount over the entire study period. Overall, these factors suggest that the range that was considered for nodal basis risk was reasonable.

Finally, the assessment of carbon price uncertainty was also reasonable. Given the political and regulatory climate in 2016, it was unlikely that any meaningful form of carbon emissions policy would be implemented at the national level in the near term. However, given the presence of regional carbon markets in the U.S. and the history of attempted carbon regulation at the national level, it was prudent to assess an outcome with a carbon price by 2030, as was done in the GFSA.

Q. Were any other variables in the study uncertain?

A. The long-term trajectory of coal prices was uncertain, as future coal price growth may not correlate with gas and power prices, as was assumed in the critical uncertain factor analysis. Since long-term coal prices for Asbury could impact the relative economic performance of Plan 1 and Plan 4 versus the alternatives, it was important to assess whether lower delivered coal costs in isolation could significantly impact the results of the GFSA. Empire and ABB performed a sensitivity analysis to test the impacts of flat coal prices (in real dollar terms)

[15] Assuming nodal basis of 86.5% (a 13.5% discount), 200% would equal a 27% discount, or 73% basis.
[16] Through August 2017, the average nodal basis at Elk River had been 0.77, or 77%.

over the full study period. Although upward pressures on coal commodity prices, and especially transportation costs, were expected in ABB's Reference Case, coal demand erosion, as a result of continued coal plant retirements, could have exerted downward pressure on the market over the long-term. Therefore, evaluating a flat coal price trajectory was reasonable and consistent with the expected coal commodity price growth rates projected in the latest AEO.

VII. REASONABLENESS OF GFSA RESULTS

Q. Did you review the results summaries produced by ABB?

A. Yes, I reviewed the income statement summaries and unit-level reports that were produced for each of the nine plans across each of the eighteen permutations of the critical uncertain factors. I also reviewed an income statement summary for a scenario that held coal prices flat in real terms.

Q. Explain how the primary cost metric, the net present value of revenue requirements or PVRR, was calculated in the GFSA results summaries.

A. The PVRR for the GFSA was calculated to summarize the overall cost impact to customers of each plan over the full time horizon under study, accounting for the time value of money. The calculation of PVRR includes all costs associated with electric power supply for the plan in question, including fuel costs, emission costs, operations and maintenance costs, and return of and on capital. The calculation discounts future years' costs back to the start of the study period, using Empire's weighted average cost of capital of 6.59%.[17] In this

[17] Confidential **Schedule JM-2**, p. 42.

analysis, the PVRR was calculated for both a 20-year period from 2018 through 2037 and a 30-year period from 2018 through 2047.

Q. What did the PVRR analysis conclude over those two time periods?

A. The analysis demonstrates that, overall, the cost of Empire acquiring new wind resources is lower than the cost of continuing to operate the existing Asbury coal plant.

Under the base case conditions and over a 20-year time horizon, the analysis concluded that Plan 2[18] showed a $325 million savings against Plan 1, the 2016 IRP preferred plan, and a $75 million savings against Plan 4, the updated plan that keeps Asbury, but also builds 800 MW of wind in 2019. Plan 3, the plan with 400 MW of wind in both low-LCOE and mid-LCOE regions, is lower cost than Plan 1 by $172 million over the 20-year time period.

Over a 30-year analysis horizon under the base case conditions, Plan 2 showed $607 million savings against Plan 1. When evaluating the expected value of each of the plans based on the assigned probabilities in the analysis of the critical uncertain factors, ABB's risk assessment reported that Plan 2 was $350 million lower cost than Plan 1.[19] The base case results over 20-year and 30-year PVRR periods are summarized in the graphics below.

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[18] Plan 2 was developed with the CEM with the new assumptions for the 2017 GFSA, allowing for Asbury to retire if economic. Plan 2 contains 800 MW of low-LCOE wind in 2019, retires Asbury in 2018, and adds solar and natural gas combined cycle units over time to meet reserve margin requirements.

[19] Work paper available upon request, Results, PVRR-Stochastic tab.

Table 1: 20 year and 30 year NPVRR for Optimized Plans[20]

		20 Year			30 Year		
Plan #	Plan Name	PVRR	Diff from Plan 1	Diff from Low	PVRR	Diff from Plan 1	Diff from Low
Plan 1	2016 IRP-Preferred Plan	$8,113	$0	$328	$10,410	$0	$607
Plan 2	Base - 800 Wind	$7,788	($325)	$3	$9,803	($607)	$0
Plan 3	Base - 400 Low and 400 Mid LCOE	$7,941	($172)	$155	$9,989	($420)	$186
Plan 4	Base + Asbury	$7,863	($250)	$78	$10,001	($409)	$198
Plan 5	High Fuel	$7,871	($242)	$85	$9,874	($535)	$71
Plan 6	Low Fuel	$7,785	($328)	$0	$9,809	($601)	$6
Plan 7	Wind-300 Mid & Low LCOE	$7,970	($143)	$185	$10,061	($349)	$257
Plan 8	Wind-200 Mid & Low LCOE	$8,032	($80)	$247	$10,195	($215)	$392
Plan 9	Wind-200 Mid & Low LCOE-No Solar	$8,037	($76)	$251	$10,219	($190)	$416

Q. Please explain why GFSA Plans 2 and 3 are lower cost than Plan 1 (the 2016 IRP preferred plan).

A. Overall, the cost of acquiring new wind resources is lower than the cost of operating and maintaining the existing Asbury coal plant. On an all-in cost basis, and based on the reasonable assumptions and methodologies described above, the cost of new wind resources was estimated to be between $22/MWh and $30/MWh (reflecting the different costs and capacity factors in low-LCOE and mid-LCOE regions), while the all-in cost of continuing to operate Asbury was estimated to be nearly $38/MWh.[21] The estimated cost of wind was driven primarily by the upfront capital costs associated with building the new potential plants and ongoing fixed operations and maintenance costs. The capital cost estimate includes the participation of tax equity partners that can take advantage of federal subsidies and pass on a lower effective cost to Empire and its customers. Most of the cost of continuing to operate Asbury (almost $25/MWh) is associated with fuel, with significant

[20] Table 1 source information, *Id.*
[21] Confidential **Schedule JM-2**, p. 5, 42.

ongoing operations and maintenance and capital costs making up the balance of the $38/MWh estimate.[22]

Q. Under what conditions does Plan 2 perform less favorably than Plan 1?

A. Plan 2[23] performs less favorably than Plan 1 (the 2016 IRP preferred plan) in the scenarios where natural gas and power market prices are low and basis congestion is high. Since the wind plans are expected to sell relatively higher amounts of energy into the wholesale market, market scenarios with lower power prices disproportionately impact these plans against Plan 1, which has fewer market sales. In the high congestion scenario, market sales revenues for the wind additions are negatively impacted by lower nodal power prices. The low-LCOE wind options are especially impacted, given the larger basis risk expected for these plants. Overall, on a 20-year PVRR basis, Plan 2 is approximately $10 million higher cost than Plan 1 in the two scenarios[24] with low gas and power prices and high basis congestion (both with and without carbon prices). On a 30-year PVRR basis, however, Plan 2 is lower cost than Plan 1 under all scenarios.[25]

The savings between Plan 2 and Plan 1 is lower under the sensitivity with flat coal prices than under the base case. In this sensitivity, the portfolios that keep Asbury in service realize lower cost inflation. However, even in this scenario, Plan 2 is $297 million lower PVRR than Plan 1 over the 20-year time period and $579 million lower PVRR than Plan 1 over the 30-year time period.[26]

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[22] *Id.*, p. 5.

[23] Plan 2 was developed with the CEM with the new assumptions for the 2017 GFSA, allowing for Asbury to retire if economic. Plan 2 contains 800 MW of low-LCOE wind in 2019, retires Asbury in 2018, and adds solar and natural gas combined cycle units over time to meet reserve margin requirements.

[24] Results, PVRR-Stochastic tab.

[25] *Id.*

[26] Results, PVRR 0% Coal Esc Scenario.

Q. Under what conditions does Plan 2 perform more favorably?

A. Plan 2 performs more favorably in scenarios where gas and power market prices are high, carbon prices are introduced, and basis congestion is low, because the revenues associated with energy sales into the market are greater under these conditions than in the base case. For example, in the scenario with a carbon price, high gas and power market prices, and low basis congestion, Plan 2 is $850 million lower cost than Plan 1 on a 20-year PVRR basis and $1,362 million lower cost than Plan 1 on a 30-year PVRR basis.[27]

Q. What are the reasons for the difference in results between the 20 and 30 year PVRR calculations.

A. For the GFSA, prices for natural gas and power are expected to increase over time, while the costs of wind are more fixed in nature, dominated by a set schedule of costs associated with recovering the initial capital investment and fixed operating costs. Therefore, the expected benefit of the wind additions grows over time, as wind generation is sold into a higher-priced market where gas-fired units are frequently on the margin and setting the market price for power. When additional years with higher market prices are evaluated in the 30-year PVRR calculation, the plans with higher levels of wind perform relatively better than the other plans.

Q. Why was the analysis conducted on a 20 and 30 year basis, and was the use of 30 year PVRR results reasonable?

A. The analysis was conducted on a 20-year basis to be consistent with the typical study horizon for Empire's past IRPs and to conform to the minimum requirements in the IRP

[27] Results, PVRR-Stochastic tab.

regulations. The 30-year basis was evaluated to assess the relative performance of the options over the expected life span of the new assets. The use of 30-year PVRR results, to support Empire's conclusions and actions regarding the addition of wind and the retirement of Asbury, was reasonable and generally consistent with utility practice to evaluate major capital decisions over their expected useful lives. Planning horizons of 25 and 30 years are used in the IRPs of other utilities in the region. Further, the 30-year analysis horizon accounts for the long-term changes that are possible in fuel, carbon, and power prices. Limiting the analysis to only a portion of the wind plants' life span would potentially omit the benefits that may accrue over time.

Q. How do the results of the GFSA compare with the results from the 2016 IRP?

A. The GFSA calculated a different PVRR for the preferred plan than what was calculated in the 2016 IRP and also concluded that a new plan with early wind additions and the retirement of Asbury was the lowest cost option for Empire, as demonstrated by the filing with the MPSC on October 17, 2018, of Empire's Notice of Change in Preferred Plan with regard to implementation of the 2018 Updated Preferred Plan. These differences of the GFSA versus the results of the 2016 IRP can be broken down into two major categories: (i) changes in general methodology and assumptions that impact all plans that were evaluated; and (ii) specific changes in assumptions for wind builds and Asbury operating costs that specifically improve the expected performance of plans with new wind relative to plans that continue operating Asbury over the long term. These changes in methodology and assumptions are discussed above.

As a result of these changes, the overall PVRR calculations generally increased relative to the 2016 IRP results, and the relative performance of new wind versus existing coal resources improved.

Q. Based on your review and experience, under what combination of market conditions and wind quality did it make sense for Empire to invest in wind?

A. The ABB analysis examined how portfolios with more wind compared to the 2016 IRP preferred plan under varying assumptions for the wind quality and the power prices at which the wind would be sold into the market. The table below depicts the forecast cost savings from adding 800 MW of strategically located wind in or near Empire's service territory and retiring Asbury under combinations of wind quality and power prices. Both 20 year and 30 year PVRR cost savings are shown.

The table illustrates that even in cases where Empire was projected to secure higher LCOE wind (second column), customers would recognize cost savings over the 2016 IRP preferred plan in all but the lower power price case. In the lower power price case, higher LCOE wind is about equivalent in cost to the 2016 IRP preferred plan.

Table 2: Cost Savings Relative to Preferred Plan (20yr / 30yr)[28]

Asbury Retirement and Build 800 MW of Wind

	Lower LCOE	Higher LCOE
Lower Market Price	$131 / $314	-$3 / $153
Base Market Price	$325 / $607	$172 / $420
Higher Market Price	$576 / $1010	$401 / $797

[28] Results, PVRR-Stochastic tab.

Q. Was it reasonable for Empire to rely on the results of the GFSA in deciding to invest in wind and retire the Asbury plant?

A. Yes. As detailed above, the GFSA includes a thorough assessment of the potential resource plans that were available to Empire at the time, using the full suite of models that are deployed during the IRP process. Using reasonable assumptions and methodology, the GFSA calculated a net present value of future revenue requirements across a range of potential plans for Empire and identified a lower cost approach for customers. My colleagues and I at CRA reviewed various elements of the analysis and advised Empire staff as it was conducted, provided input on assumptions development, portfolio creation, and uncertainty analysis, reviewed detailed results to check outputs and synthesize key findings, and also assessed the reasonableness of the approach and assumptions based on our extensive experience with utility resource planning tools, processes, and current trends in the electricity markets.

VIII. <u>CUSTOMER SAVINGS RELATING TO THE RETIREMENT OF ASBURY</u>

Q. Does the retirement of Asbury result in savings to customers and if so what is the amount of those savings?

A. Yes, based on the 2019 IRP, retiring Asbury results in savings of approximately $93 million on a 20-year expected value basis. From a risk perspective, retiring Asbury also demonstrated significant savings. Under the 54 stochastic endpoints, retiring Asbury resulted in savings over maintaining Asbury until end of life 94% of the time, on a probability-weighted basis. Savings range from $18 million to $144 million. Only under limited combinations of high capital costs, high gas and power prices, and no carbon price did retiring Asbury not reduce costs.

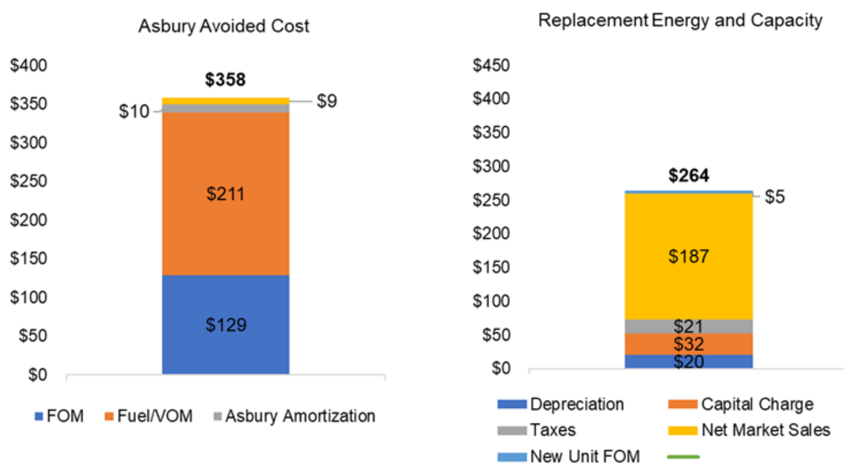
Q. Does Empire's analyses of cost savings relating to the retirement of Asbury take into account Empire's request in this proceeding for customers to continue to pay the pre-tax return on the retired investment?

A. Yes. The customer savings calculated in the GFSA assumed that customers would pay the remaining outstanding balance on Asbury over 30 years, the cost of the capital, and decommissioning costs. The cost of the capital reflects the cost of debt and the allowed return on equity, calculated on a pre-tax basis.

Q. Can you provide a breakdown of the $93 million in present value savings that customers will be receiving over the next 20 year period as a result of Empire's decision to retire Asbury?

A. Yes. Savings will result from the costs that are avoided by retiring Asbury *less* the costs of the replacement capacity and energy required to meet Empire's customer needs. The figure below provides an illustration. On a present value basis, retiring Asbury is expected to avoid approximately $129 million in fixed O&M costs, $211 million in fuel and variable O&M costs, and $9 million in avoided capital charges. Costs are also lower from spreading the unamortized plant balance over a longer period than the original depreciation schedule. The cost of replacement capacity and energy relates to the incremental cost of solar and storage – reflected as depreciation, capital charge, and taxes below - and the difference in market sales and purchases between the plans with and without Asbury. The difference between the $358 million and $264 million below is the $93 million in savings that I described above.

Figure 2: Difference Between IRP Plan 4 and Plan 0



IX. <u>CAPACITY RESERVE MARGINS</u>

Q. Did Empire's decision to acquire 600 MW of wind take into account Empire's capacity reserve margin?

A. Yes. The analysis considered what was minimally needed to ensure reliable capacity to serve load.

Q. Why would it be appropriate for a utility to have a capacity reserve margin significantly above the required minimum?

A. Utilities often procure well beyond a required minimum for several reasons: (1) to avoid the risk of falling short of meeting their requirements; (2) as a result of the block size of new resources they procure; (3) to provide flexibility in decision making; and (4) as a result of a transformation that may require investment and divestment that cannot practically happen all at once.

Q. Why is it necessary for Empire to add 600 MW of additional wind resources to its portfolio if it would increase its capacity reserve margin above the minimum?

A. Empire assessed the need for 600 MW of wind on the basis of a portfolio analysis that looked at many factors, including the minimal required reserve margin. Empire's analysis, which formed the basis for its Change in Preferred Plan filing on October 17, 2018[29], showed that adding 600 MW of wind to its portfolio had significant benefits for its customers. These benefits included substantially lowering the net present value revenue requirement of the Empire generation portfolio and significantly reducing portfolio cost risk.

As with other electric utilities, Empire must seek not only to meet demand (both capacity and energy), but to do so in the most economical manner. The most economical approach is to add low cost renewable wind energy, continue to rely on its existing generation for capacity and replace some of the more expensive energy from those generation sources with energy from new wind projects. The prices from the new wind projects are competitive in the SPP IM. While customers benefit from the lower cost of energy they will also benefit from emission free resources, including Kansas resources, and effectively create a hedge against future environmental rules, whether that be a new Clean Power Plan or some other form of environmental regulation and allow Empire to meet current renewable energy resources goals set by the states in which it operates.

Q. Could these benefits have been achieved without increasing the capacity reserve margin?

A. No. The phase out and expiration of federal production tax credits for wind necessitated that Empire move quickly to add wind to its portfolio. To capture the full production tax credit, a qualifying wind project must enter service by the end of 2020. The full production tax credit incentive is expected to reduce the effective capital cost of the Empire wind

[29]Empire's Notice of Change in Preferred Plan. In the Matter of The Empire District Electric Company's Change to its 2016 Utility Resource Filing Pursuant to 4 CSR 240 – Chapter 22 (October 17, 2018).

projects by more than half. During the modeling performed by Empire, the wind projects had an effective capital cost of $711/kW, putting the projects on a parity with a new combined cycle gas plant, but without any fuel costs.[30]

In its modeling, Empire identified the optimal amount of wind to support its objectives of lowering customer costs and reducing portfolio cost risk, while simultaneously improving the overall environmental attributes of the portfolio. Empire's analysis showed that adding 800 MW of wind and retiring the Asbury coal plant would reduce cost and cost risk to Empire's customers. Empire agreed to reduce its wind request to 600 MW as part of a stipulation with certain stakeholders in its MPSC proceedings and to review the retirement of Asbury in its 2019 IRP.

Notwithstanding the demonstrated benefits of rebalancing the portfolio with *more* wind, Empire's application presents a low-cost opportunity to replace 255 MW of wind associated with the Elk River and Meridian Way Power Purchase Agreements, expiring in the mid- to late 2020s and to meet the renewable energy resource goals set by the states in which Empire conducts its utility operations.[31]

In addition, and as previously stated in my testimony, implementation of the SPP IM has introduced much more flexibility to Empire's generation dispatch and has increased the amount of wind energy that it can economically deploy.

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[30]Affidavit in Support of Non-Unanimous Stipulation and Agreement of James McMahon. (April 24, 2018) Case No.: EO-2018-0092. Page 4.

[31]The Elk River wind PPA for 150 MW expires in 2026. The Meridian Way wind PPA for 105 MW expires in 2028.

Q. Does Empire expect to maintain this higher capacity reserve margin indefinitely?

A. Empire's 2019 IRP addressed the timing of retirements and additions beyond the planned 600 MW of wind. Based on extensive portfolio analysis, Empire's 2019 IRP selected Plan 4 as the Preferred Plan. Plan 4 was developed to analyze the "early" retirement of Asbury in 2019 and the costs and benefits of adding a mix of distributed and utility-scale renewables. In addition to the retirement of Asbury, Plan 4 called for the retirement of Empire Energy Center #1 and #2 in 2026 (approximately 150 ICAP MW) and Riverton #10 and #11 in 2033 (approximately 28 ICAP MW). The Preferred Plan also included the scheduled 2025 expiration of the Elk River wind PPA (150 ICAP MW representing 22 UCAP MW) and the 2028 expiration of the Meridian Way solar PPA (105 ICAP MW representing 9 UCAP MW).

Based on the planned retirements and known PPA expiration dates, and absent any portfolio additions (excluding the planned 600 MW of wind), the 2019 IRP forecasted a capacity shortage of approximately 87 UCAP MW in 2027, rising to approximately 160 UCAP MW in 2038, based on SPP's 13.6 percent planning reserve margin at the time. To address this capacity shortage, Plan 4 called for the addition of 19.5 ICAP MW of distributed solar plus storage in 2022 and in 2028 and 13.5 ICAP MW of distributed solar plus storage in 2032 and in 2036. Plan 4 also called for 50 ICAP MW of utility-scale solar in 2023 and in 2034, as well as 50 MW of utility-scale solar plus storage in 2027. Plan 4 also included a 35 MW upgrade at the Stateline Combined Cycle facility.

In addition to the changes in the planned portfolio described above, recent changes to Empire's load forecast further contribute to a decreasing capacity reserve margin. As of June 1, 2020, Empire's two largest municipal electric customers, the cities of Monett and

Mount Vernon, Missouri, as well as the city of Chetopa, Kansas were no longer on-system wholesale customers. The loss of this system load was reflected in the 2019 IRP load forecast and represented approximately a 6 percent energy reduction for the Empire system. However, Empire recently entered in a five-year power purchase agreement with the Missouri Joint Municipal Utility Commission ("MJMEUC") for a capacity and energy sale beginning June 1, 2020 and ending May 31, 2025 for the two Missouri municipals, representing a total capacity sale of 78 MW during the agreement period. This 78 MW sale was not shown in the 2019 IRP. Including this load further leads to a declining Empire reserve margin over time.

Q. Does this conclude your direct testimony?

A. Yes, it does.

AFFIDAVIT OF JAMES MCMAHON

STATE OF NEW HAMPSHIRE)
) **ss**
COUNTY OF HILLSBOROUGH)

On the 24th day of May, 2021, before me appeared James McMahon, to me personally known, who, being by me first duly sworn, states that he is Vice President, Charles River Associates, and acknowledged that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

James McMahon

Subscribed and sworn to before me this 24th day of May, 2021.

Notary Public

My commission expires: ANA CAROLINA D. COELHO
Notary Public, State of New Hampshire
My Commission Expires March 11, 2025