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Direct Testimony

of

James McMahon

****Denotes Confidential****

Empire District
A Liberty Utilities Company

PUBLIC VERSION

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I. BACKGROUND

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 JOB FUNCTION.

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 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 AND WHAT POSITIONS DID YOU HOLD PRIOR TO CRA?

A. I have been in my current role at CRA since 2014 and have approximately twenty years of experience in energy consulting with CRA and other firms.

Q. WHAT IS YOUR EDUCATION?

A. I hold a JD and MBA from the College of William and Mary, and a BA in Economics from Tufts University. A copy of my resume is attached to my testimony as **Direct Attachment JM-1.**

II. <u>OVERVIEW OF TESTIMONY</u>

Q. CAN YOU PLEASE DESCRIBE THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony reviews The Empire District Electric Company's ("Empire") recent Generation Fleet Savings Analysis and how it compares to its 2016 Integrated Resource Plan (the "2016 IRP"). I explain the analysis that was conducted and review the approach, modeling tools, methodology, assumptions, and results.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of this section describes CRA's role in the Generation Fleet Savings Analysis and my experience with utility resource planning. The next section summarizes the major results of the analysis and the major differences with the 2016 IRP. I then review the approach that was taken in conducting the Generation Fleet Savings Analysis and comment on the reasonableness of the modeling tools, analysis methodology, portfolio construction process, and assumptions. The final section provides a detailed review of the key findings.

Q. CAN YOU EXPLAIN EMPIRE'S GENERATION FLEET SAVINGS ANALYSIS AND YOUR ROLE IN ITS DEVELOPMENT?

A. Empire conducted the Generation Fleet Savings Analysis 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. A copy of The Generation Fleet Savings Analysis is attached to my testimony as **Direct Attachment JM-2.** 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. It 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.

Q. WHERE DID YOU PROVIDE INPUT ON THE ANALYSIS?

A. 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. DESCRIBE YOUR EXPERIENCE WITH INTEGRATED RESOURCE 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 over the last several years. This work has been performed on behalf of utilities located across the country representing diverse portfolios of resources. My work has involved scenario development, portfolio modeling and analysis, tradeoff analysis, and stakeholder support, among other things.

CRA is the consultant of public record to NIPSCO and Southern Company on IRP-related issues. For NIPSCO, an Indiana utility with around 3,000 MW of primarily coal and natural gas resources, CRA performs all generation modeling and IRP analysis for the company. For Southern Company, the owner of four utilities in the Southeast U.S., CRA annually develops planning scenarios and fuel forecasts in support of the utility IRPs and the company's overall budget.

Q. DESCRIBE YOUR EXPERIENCE WITH IRP MODELS LIKE THOSE USED IN EMPIRE'S IRP AND GENERATION FLEET SAVINGS ANALYSIS.

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 Enterprise Software Inc. ("ABB") in the Generation Fleet Savings Analysis, 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.

Q. HAVE YOU PERFORMED SIMILAR REVIEW OF MARKET FORECASTS AND RESOURCE PLANNING ANALYSIS IN THE PAST?

A. Yes. CRA is regularly asked to review other consultant market forecasts and analyses in the context of asset transactions and in resource planning. This has involved reviewing and deriving key drivers of market price forecasts, reviewing and commenting on modeling methodologies, and opining on the conclusions reached by other consultants.

In a recent resource planning assignment for a Southeastern utility, CRA worked on behalf of one owner in a large shared project to review assumptions, modeling methodology, and conclusions reached by their in-house team using ABB models and third-party price forecasts. CRA reviewed input assumptions for reasonableness and assessed the major uncertainties that drove the utility's decision.

Another recent example involves CRA's work for a large Midwestern utility. One activity involved replicating a resource planning analysis developed originally by the company in ABB's models. CRA reviewed all of the assumptions and modeling methods and replicated the results within a reasonable range.

III. SUMMARY OF MAIN CONCLUSIONS OF THE GENERATION FLEET SAVINGS ANALYSIS

Q. CAN YOU SUMMARIZE THE PRIMARY FINDINGS OF THE GENERATION FLEET SAVINGS ANALYSIS?

A. The analysis found that the lowest cost way for Empire to serve its load obligations over the next twenty to thirty years is to undertake a near-term strategy that builds up to 800 MW of wind strategically located wind in or near Empire's service territory in 2019 and 2020 and retires the Asbury coal plant in 2018 or 2019[1]. Wind in regions with high capacity factors (hereafter referred to as "low-levelized cost of electricity" or "low-LCOE" wind) is expected to be lower cost for customers, but if Empire is constrained on the amount that can be built in these regions, additional wind in regions with lower capacity factors (hereafter referred to as "mid-LCOE" wind) is still cost effective. A plan with 800 MW of low-LCOE wind is projected to realize a $325 million[2] savings against the Preferred Plan from the 2016 IRP on a 20-year net present value of revenue requirements ("PVRR") basis and a $607 million[3] savings on a 30-year PVRR basis.[4] A plan with 400 MW of low-LCOE wind and 400 MW of mid-LCOE wind is projected to realize a savings of $172 million[5] on a 20-year PVRR basis and a savings of $420 million[6] on a 30-year basis.

Q. CAN YOU DESCRIBE FURTHER WHAT IS MEANT BY THE LEVELIZED COST OF ELECTRICITY (LCOE) AND HOW IT IS GENERALLY CALCULATED FOR WIND RESOURCES?

[1] The modeling assessment assumed an Asbury retirement at the end of 2018; however, Empire indicated that it is possible that Asbury would be retired in the Spring of 2019.
[2] *Exhibit GFSA Results*, PVRR-Base tab
[3] *Id.*
[4] The Preferred Plan from the 2016 IRP was modeled under the new assumptions in the Generation Fleet Savings Analysis.
[5] *Exhibit GFSA Results*, PVRR-Base tab
[6] *Id.*

A. In general, the levelized cost of electricity is a measure of the lifetime costs of a technology divided by its total expected production. For a wind asset, lifetime costs could include construction and interconnection, operations and maintenance, capital upgrades, and the cost of capital. Production of wind will depend on the location of the asset (e.g., consistency and strength of the wind) and the technology that is deployed (e.g., size, turbine efficiency).

Q. HOW ARE THESE CONCLUSIONS DIFFERENT THAN 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 and early 2030s. Therefore, it did not recommend near-term action around new builds or retirements.

Q. WHAT ARE THE MAJOR DRIVERS OF DIFFERENCES IN THE FINDINGS OF THE GENERATION FLEET SAVINGS ANALYSIS AND THE 2016 IRP?

A. Several changes in methodology and assumptions were made between the two studies, with three major changes driving the new findings. First, the new analysis updated the assumptions for wind capital costs, reflecting recent declines and the ability for Empire's to work with tax equity partners; Second, the new analysis updated the capacity factor expectations for new wind plants, reflecting recent technology improvements and observed performance of operating plants. Third, the new analysis modeled the SPP Integrated Marketplace, 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 pricing detail.

Q. ARE THESE UPDATED ASSUMPTIONS AND THE ASSOCIATED CONCLUSIONS REASONABLE BASED ON YOUR REVIEW OF THE ANALYSIS AND YOUR EXPERIENCE IN THE UTILITY INDUSTRY?

A: Yes, the updates to methodology and assumptions reflect current market conditions and represent a reasonable way of conducting this analysis. I also believe that the conclusions that are presented in the Generation Fleet Savings Analysis are reasonable based on the input assumptions and the modeling approach that was deployed.

IV. DESCRIPTION OF APPROACH FOR THE GENERATION FLEET SAVINGS ANALYSIS

Q. WHY WAS THE GENERATION FLEET SAVINGS ANALYSIS DEVELOPED?

A. As part of the ongoing obligation to review its resource acquisition strategy in the context of its IRP requirements Empire, in conjunction with its new owners, Algonquin Power & Utilities Corp., 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. CAN YOU DESCRIBE THE GENERAL PROCESS FOR THE DEVELOPMENT OF THE GENERATION FLEET SAVINGS ANALYSIS?

A. Empire updated several modeling inputs and assumptions and engaged 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 Generation Fleet Savings Analysis.

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 analysis. I understand that ABB has worked with Empire for more than ten years in this capacity to develop market forecasts and support IRP analysis.

Q. PLEASE 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.

V. REASONABLENESS OF MODELING TOOLS AND METHODOLOGY

Q. DESCRIBE THE DETAILS OF THE ANALYTICAL TOOLS USED IN THE GENERATION FLEET SAVINGS ANALYSIS 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 Generation Fleet Savings Analysis. 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 respecting a number of constraints like the minimum reserve margin level and maximum amounts of certain resource options like wind. 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 a full dispatch simulation of each portfolio as well as full financial accounting in order to estimate Empire's revenue requirement for each plan considered. The Strategic Planning Module dispatches the Empire fleet based on a set of market inputs for fuel, emissions, and power prices in chronological fashion, calculating market sales and purchases transactions with the SPP market. It combines the results of the variable cost dispatch analysis with a 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 Missouri's rules for resource planning, as they "consider and analyze demand-side efficiency and energy management measures on an equivalent basis with supply side alternatives," 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" (4 CSR § 240-22.010). It is our understanding that since Kansas does not have IRP regulatory requirements, Empire has provided the Kansas Corporation Commission Staff the executive summary of its Missouri IRP filing and met annually with the Staff to discuss its IRP filing. Using these models is also consistent with the Oklahoma Corporation Commission's ("OCC") IRP rules and has been used previously in IRPs submitted in Oklahoma (OAC 165:35-37-4). The use of these models is also consistent with the Arkansas Public Service Commission's requirements to "utilize an integrated planning and acquisition/implementation process that will maximize available cost savings and benefits for its customers" (Docket No. 06-028-R Order No. 6).

Q. WAS IT REASONABLE TO START WITH THE 2016 IRP INSTEAD OF CONDUCTING A NEW IRP PROCESS?

A. Yes, the 2016 IRP was recently completed and contained all of the core data associated with Empire's base portfolio that is used to calculate its revenue requirement. Therefore, the 2016 IRP served as a reasonable comparison point against which to update several important assumptions changes, which I will explain in more detail later. The 2016 IRP Preferred Plan was also a reasonable benchmark against which to evaluate different potential plans that build additional wind and retire Asbury.

Q. WHY WAS IT NECESSARY TO UPDATE THE MODELING FRAMEWORK TO INCLUDE FULLER TREATMENT OF THE SPP INTEGRATED MARKETPLACE, INCLUSIVE OF NODAL PRICING BASIS?

A. SPP launched its Integrated Marketplace 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.[7] 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

[7] 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.

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 Generation Fleet Savings Analysis 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 when IRP assumptions were being developed in 2015. 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 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. Essentially, 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 is assigned a probability, and a weighted average calculation is performed across all outcomes to calculate an expected value of the revenue requirement. This approach also allows for examination of each unique pathway, represented by a potential combination of different uncertain factor outcomes, in order to evaluate the various plans against each other under different input assumptions.

Q. IS THIS METHODOLOGY CONSISTENT WITH IRP REGULATORY REQUIREMENTS?

A. Yes, the Missouri IRP rules require that the risk assessment "include a decision-tree representation of the key decisions and uncertainties associated with each resource plan" and that "the utility shall use the decision-tree formulation to compute the cumulative probability distribution of the values of each performance measure" 4 CSR § 240-22.070. ABB's analysis approach is consistent with these requirements. As noted earlier, it is my understanding that since Kansas does not have IRP regulatory requirements, Empire has provided the Kansas Corporation Commission Staff with information regarding its Missouri IRP filing. This methodology is also consistent with Oklahoma rules, which require utilities to assess "important uncertainties, including but not limited to load growth, fuel prices and availability of planned supplies" OAC 165:35-37-4(c)(11).

VI. REASONABLENESS OF PORTFOLIO CONSTRUCTION

Q. DID EMPIRE INCLUDE A 10 YEAR LOAD FORECAST IN ITS GENERATION FLEET SAVINGS ANALYSIS?

A. Yes, Empire relied upon the load forecast developed in the 2016 IRP process and evaluated resource options necessary to meet expected peak load plus a reserve margin.

Q. CAN YOU GENERALLY DESCRIBE THE RESULTS OF THAT 10 YEAR LOAD FORECAST?

A. The load forecast projects a compound annual growth rate for both winter and summer peak load of 0.3% over the study period. Over the near-term period, the winter peak load is expected to grow from 1,151 MW in 2017 to 1,170 MW in 2022, while summer loads are expected to be flatter.

Q. IN CONDUCTING ITS GENERATION FLEET SAVINGS ANALYSIS, DID EMPIRE CONSIDER GENERATION/SUPPLY, TRANSMISSION, AND DEMAND RESPONSE ALTERNATIVES OR OPTIONS THAT MIGHT BE REASONABLY AVAILABLE TO THE UTILITY?

A. Yes, as noted above, the Generation Fleet Savings Analysis started with the 2016 IRP, which conducted a full review of all options that might be reasonably available to Empire. The updated analysis changed certain assumptions, but still evaluated a broad suite of options.

Q. CAN YOU DESCRIBE THE SUPPLY, TRANSMISSION, AND DEMAND RESPONSE ALTERNATIVES OR OPTIONS THAT EMPIRE DETERMINED WERE REASONABLY AVAILABLE?

A. An extensive list of supply-side generation resources and market opportunities was evaluated in the 2016 IRP and in the Generation Fleet Savings Analysis. 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[8].

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 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 Generation Fleet Savings Analysis, one of these DSM options was incorporated in all portfolios, as discussed in more detail in the next section.

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[8] *Exhibit Capital Cost Assumptions*, Supply Side Alternatives Table tab

Q. CAN YOU DESCRIBE THE SPECIFIC DETAILS OF THE DIFFERENT PLANS OR PORTFOLIOS THAT WERE ANALYZED IN THE GENERATION FLEET SAVINGS ANALYSIS?

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

Figure 1: Optimized Plans from Generation Fleet Savings Analysis[9]

	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

[9] *Generation Fleet Savings Analysis*, p.11

assumptions for the 2017 Generation Fleet Savings Analysis, 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. Plan 3 constrains the amount of low-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 the end of its life in 2035. As a result, it builds solar and natural gas combined cycles later than the other plans, but still builds 800 MW of low-LCOE wind in 2019. Plan 5 was developed with the CEM with 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 low-LCOE 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 low-LCOE 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, it 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?

A. The plans were developed using the CEM in the same fashion that they were in the 2016 IRP, allowing 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. And for comparison to last year's analysis, the Preferred Plan from the 2016 IRP was included as an important benchmark.

Q. WHY WERE THESE 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 DESCRIBE THE CONSTRAINTS OR WIND BUILDS FURTHER.

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 Integrated Marketplace, 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[10] to be tested. Although wind resources are assumed to count for 15% capacity credit[11], the constraint of up to 800 MW of new wind still allows for these additions to replace a sizeable portion of the Asbury capacity that may retire, while delaying the need for future fossil-fired capacity builds.

VII. <u>REASONABLENESS OF EMPIRE'S ASSUMPTIONS</u>

Q. CAN YOU EXPLAIN IN MORE DETAIL THE ASSUMPTIONS CHANGES THAT WERE MADE BETWEEN THE 2016 IRP AND THE 2017 GENERATION FLEET SAVINGS ANALYSIS?

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[10] Wind capacity was limited to 1,100 MW total. Since 255 MW of wind capacity already exists 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.

[11] Note that each wind farm in SPP is subject to a detailed coincident peak assessment to determine accredited capacity. It is expected that new wind projects will receive approximately 15% credit, although this number will ultimately be dependent on actual operations.

A. Six notable assumption changes that influence the drivers described earlier were made between the 2016 IRP and the 2017 Generation Fleet Savings Analysis. They include the following:

- First, the 2017 analysis assumed open access for Empire 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 Integrated Marketplace 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 demand side management ("DSM") measures, adopted in 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.
- 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 NECESSARY TO MAKE THESE ASSUMPTIONS 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 past one to two years. The growing maturity of SPP's Integrated Marketplace 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 THE 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 Generation Fleet Savings Analysis. 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 REFERENCE CASE ASSUMPTIONS COMPARE WITH THE ASSUMPTIONS USED IN THE 2016 IRP, AND WHAT WERE THE REASONS FOR ANY DIFFERENCES?

A. The natural gas and power market price forecasts used in the Generation Fleet Savings Analysis are lower than those used in the 2016 IRP, which were based on ABB's Spring 2015 Reference Case. The natural gas price forecast has come down as a result of continued low-cost domestic production and increases in estimated reserves, which has been reflected in lower market forwards. The power price forecast has come 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 have followed the same general downward trend in recent years. The U.S. Energy Information Administration publishes an Annual Energy Outlook (AEO)[12], 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 Generation Fleet Savings Analysis follow a similar trajectory as those

12 https://www.eia.gov/outlooks/aeo/

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 have driven the outlook down in recent years. The graphic below provides a comparative summary.

Figure 2: Natural Gas Price Comparisons

****<u>Confidential in its entirety</u>****

Q. DO ANY OF THE ABB MARKET FORECASTS GET ADJUSTED PRIOR TO BEING DEPLOYED IN THE IRP MODELS?

A. Yes, in a couple of instances. As I mentioned earlier, 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 Integrated Marketplace, 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-Missouri price forecast. The new wind options 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[13]. Given that specific sites for new wind projects have not been identified, using data from these locations is 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 GENERATION FLEET SAVINGS ANALYSIS?

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

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 as a result of receiving 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 with wind plants.

Q. WHAT CAPITAL COST ASSUMPTIONS WERE USED FOR THE NEW WIND OPTIONS UNDER THE FLEET SAVINGS ANALYSIS AND UNDER THE 2016 IRP?

A. In the 2016, IRP Empire assumed that new wind would cost $2050/kW ($2016). The Generation Fleet Savings Analysis assumed that new wind would cost $1,660/kW ($2016) in 2019 and $1,642/kW ($2016) in 2020[14]. As a result of the expected partnership with tax equity investors, Empire is expected to only contribute 46.8% of the upfront capital costs for plants that come online by 2020 for mid-LCOE projects and 40.4% for plants that come online by 2020 for low-LCOE projects, since these projects can take advantage of the full production tax credit[15]. The lower percentage for low-LCOE projects reflects higher assumed production tax credits from higher plan capacity

[14] *Exhibit Capital Cost Assumptions*, Wind Capital Cost Assumptions tab
[15] *Id.*

factors. Therefore, the net capital cost contribution for Empire for a mid-LCOE plant coming online in 2020 is $769/kW, while the net contribution for a low-LCOE plant coming online in 2019 is $671/kW. For comparison, for low-LCOE plants that come online in 2022, the all-in capital cost is assumed to be $1,606/kW, while the Empire contribution is 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 are 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[16]. Other commonly-sourced public reviews of wind capital costs performed by Lazard and the Lawrence Berkeley National Laboratory ("LBNL") have recently estimated new wind builds costs of $1,475/kW and $1,587/kW, respectively[17].

Q. WERE TRANSMISSION INTERCONNECTION COSTS ALSO INCLUDED IN THE ANALYSIS?

A. Yes, Empire also separately developed interconnection costs estimates and assumptions for additional transmission system upgrades that will likely be required for new projects. Costs in low-LCOE regions are assumed to be approximately $123/kW, while costs in mid-LCOE regions are assumed to be approximately $31/kW[18].

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[16] *Exhibit Wind Cost Estimates*, tab Summary
[17] *Id.*
[18] *Exhibit Generation Fleet Savings Analysis*, p. 26

Q. WHAT WAS ASSUMED FOR FIXED OPERATIONS AND MAINTENANCE ("FOM") COSTS FOR NEW WIND?

A. Empire assumed FOM costs of approximately $50/kW-yr for the new wind additions based on recent experience with wind projects. This estimate is 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 $29-55/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. 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 is assumed to be 46%, while the annual capacity factor of new low-LCOE projects is assumed to be 54%[19].

Q. GIVEN THESE ASSUMPTIONS, WHAT LEVELIZED COST OF ELECTRICITY WAS ASSESSED FOR THE WIND OPTIONS?

A. The levelized cost of electricity is estimated to be $21.52/MWh for low-LCOE wind and $29.71/MWh for mid-LCOE wind[20].

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[19] *Id at 21, 22.*
[20] *Generation Fleet Savings Analysis*, p.35

Q. WILL EMPIRE CONFIRM ALL OF THESE INPUT ASSUMPTIONS THROUGH A COMPETITIVE SOLICITATION PROCESS BEFORE NEW RESOURCES ARE ACQUIRED?

A. Yes, I understand that Empire has solicited competitive bids for certain qualifying wind generation facilities pursuant to a formal Request for Proposal, which is described by Company witness Wilson.

Q. WHICH INPUT VARIABLES DID EMPIRE IDENTIFY AS CRITICAL UNCERTAIN FACTORS, 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. 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 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 Generation Fleet Savings Analysis. 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 is less important for the Generation Fleet Savings Analysis. Although the capital costs of wind are a major driver of wind plan economics, all of the potential significant additions in the Generation Fleet Savings Analysis plans are near-term acquisitions where a level of price transparency already exists for Empire decision makers. Therefore, long-term uncertainty is less important. Similarly, long-term load uncertainty will 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, is available.

Nodal basis risk has been introduced as a new critical uncertain factor, given the new modeling of the SPP Integrated Marketplace and the locational price uncertainty that exists for generators as a result. This is especially true for wind plants which are often located far from load centers and subject to low price risk. Therefore, it is 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 UNCERTAINTY ANALYSIS REASONABLE?

A. Yes, the ranges evaluated appear to capture a reasonable band of upside and downside uncertainty for each of the critical uncertain factors. The high natural gas price trajectory extends above **____ ____ ____ ____. ** 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 Generation Fleet Savings Analysis covers a plausible downside reflective of current market sentiment and fundamental analysis.

The ranges used for the nodal basis also appear to capture a reasonable band of potential outcomes. Given the potential for downside pricing risk, especially around wind plants, it is prudent to stress basis change that results in lower prices at the wind nodes, and Empire has 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 is expected to be only 86.5% of the prices at which Empire buys electricity to serve its native load. In the high basis case, this expands to 0.73 or 73%.[21] This level more than covers the recent discount that has been observed in 2017 year-to-date.[22] It also assumes a persistent discount over the entire study period. Although transient periods of significant discounts

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

are possible, long-term transmission expansion and potential integration of storage and other fast response resources are likely to minimize the persistence of such significant discounts. Further, I understand that Empire is attempting to mitigate against this risk by preferring projects east of the major existing transmission constraints in Kansas. Overall, these factors suggest that the range that has been considered for nodal basis risk is reasonable.

Finally, the assessment of carbon price uncertainty was also reasonable. Given the current political and regulatory climate, it is unlikely that any meaningful form of carbon emission policy will 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 is prudent to assess an outcome with a carbon price by 2030, as has been done.

Q. ARE ANY OTHER VARIABLES IN THE STUDY UNCERTAIN, AND COULD THEY SIGNIFICANTLY IMPACT THE OUTCOME?

A. The long-term trajectory of coal prices is uncertain, and future coal price growth may not be correlated 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 is important to assess whether lower delivered coal costs in isolation could significantly impact the results of the Generation Fleet Savings Analysis. Empire and ABB performed a sensitivity to test the impacts of flat coal prices (in real dollar terms) over the full study period. Although upward pressures on coal commodity prices, and especially transportation costs, are expected in ABB's reference case, coal demand erosion, as a result of continued coal plant retirements, could exert downward pressure on the market over the long-term. Therefore, evaluating a flat coal price trajectory is reasonable and is consistent with the expected coal commodity price growth rates projected in the latest AEO.

VIII. REASONABLENESS OF 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, IS CALCULATED IN THE RESULTS SUMMARIES.

A. The PVRR is 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%[23]. In this

[23] *Generation Fleet Savings Analysis,* p.35

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. Under the base case conditions and over a 20-year time horizon, the analysis concluded that Plan 2 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[24]. The base case results over 20-year and 30-year PVRR periods are summarized in the graphics below.

[24] *Exhibit GFSA Results*, PVRR-Stochastic tab

Table 1: 20 year and 30 year NPVRR for Optimized Plans[25]

		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. EXPLAIN WHY 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, the cost of new wind resources is 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 is estimated to be nearly $38/MWh[26]. The cost of wind is 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

[25] *Id.*

[26] *Generation Fleet Savings Analysis*, p.2

significant ongoing operations and maintenance and capital costs making up the balance of the $38/MWh estimate[27].

Q. UNDER WHAT CONDITIONS DOES PLAN 2 PERFORM LESS FAVORABLY?

A. Plan 2 performs less favorably 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[28] 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[29].

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

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[27] *Id.*
[28] *Exhibit GFSA Results*, PVRR-Stochastic tab
[29] *Id.*

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[30].

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[31].

Q. EXPLAIN THE REASONS FOR THE DIFFERENCE IN RESULTS BETWEEN THE 20 YEAR AND 30 YEAR PVRR CALCULATIONS.

A. 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.

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[30] *Exhibit GFSA Results*, PVRR 0% Coal Esc Scenario
[31] *Exhibit GFSA Results*, PVRR-Stochastic tab

Q. WHY WAS THE ANALYSIS CONDUCTED ON A 20 YEAR AND 30 YEAR BASIS, AND IS 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 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 is reasonable and is 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, including AEP's subsidiaries (Southwestern Electric Power Company and Public Service Company of Oklahoma), Oklahoma Gas & Electric, and Ameren's Union Electric Company in Missouri. 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 FROM THE GENERATION FLEET SAVINGS ANALYSIS COMPARE WITH THE RESULTS FROM THE 2016 IRP?

A. The Generation Fleet Savings Analysis 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. These differences 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.

General changes in methodology and assumptions include updating the first year of the study from 2016 to 2018, modeling the SPP Integrated Marketplace, including the RAP DSM program in all plans, and updating the market forecasts, including removing the carbon price in the base case. Specific changes in assumptions for the wind additions and Asbury include reduced constraints on the amount of wind that could be built and the subsequent volume of energy sold to the market; updated capital cost estimates for wind builds that reflect lower pricing and the participation of potential tax equity partners; improved capacity factor projections for new wind assets, reflecting observed technology improvements; and fuller accounting of the ongoing impact of removing Asbury from the portfolio, including refined accounting of future fixed cost and maintenance capital obligations that would disappear if the plant is retired.

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

Q. CAN YOU EXPLAIN THE RELATIVE AND DIRECTIONAL INFLUENCE OF EACH OF THESE FACTORS IN MORE DETAIL?

A. Overall, the shift in study period and the incorporation of DSM costs raise the reported PVRR between the 2016 IRP Preferred Plan and the same plan in the updated analysis and explain the large majority of the overall PVRR cost increase between the two analyses. Beyond those adjustments, updates to Asbury accounting, especially regarding ongoing capital expenditures, drive costs higher, while improved wind parameters drive the costs lower, even prior to the incorporation of early wind additions. Lower natural gas and carbon prices drive costs for Empire's generating fleet lower, while changes related to the SPP power market drives costs higher. This is because, on balance, Empire's portfolio sells more into the market than it buys, so lower power prices and the incorporation of nodal discounts for generation resources drives the total portfolio cost higher.

The new preferred plan with wind, Plan 2, is lower cost than Plan 1 due primarily to the benefits associated with adding wind to the portfolio, which is reflected through updated cost and capacity factor assumptions and the ability to sell energy into the market. The reduction in costs associated with avoiding future expenditures for Asbury are also relevant to the overall difference in costs between Plan 1 and Plan 2, but are not as substantial as the benefits associated with new wind.

Q. BASED ON YOUR REVIEW, UNDER WHAT COMBINATION OF MARKET CONDITIONS AND LCOE DOES IT MAKE SENSE FOR EMPIRE TO INVEST IN WIND?

A. The ABB analysis examined how portfolios with more wind compared to the 2016 Preferred Plan under varying assumptions for the wind LCOE 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 LCOE for wind and power prices. Both 20 year and 30 year PVRR cost savings are shown.

The table illustrates that in all cases where Empire is able to secure lower LCOE wind (first column), customers will recognize cost savings on an PVRR basis relative to the Preferred Plan. Even in cases where Empire secures higher LCOE wind (second column), customers will 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)[32]

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

Q. WHAT VALUES FOR LCOE AND MARKET PRICES WERE ASSUMED IN THE TABLE ABOVE?

A. The Lower LCOE case assumed an LCOE of approximately $22/MWh. The Higher LCOE case assumed an LCOE of approximately $24/MWh[33]. The lower, base, and higher market price forecasts correspond to the low, base, and high market price cases run by ABB.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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[32] *Exhibit GFSA Results*, PVRR-Stochastic tab
[33] *Exhibit Generation Fleet Savings Analysis*, p.2

C. James McMahon

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James McMahon is Vice President with the Energy Practice of CRA. Mr. McMahon is experienced in generator economics and cost of service analysis for utilities and power-related projects. For the last 18 years Mr. McMahon has provided expert support and management consulting to the energy sector, with specific emphasis on electric utilities, independent power producers, and RTOs/ISOs. Mr. McMahon has led or been a key expert in more than 100 projects involving a range of topics, including integrated resource planning, competitive project evaluation under FERC Order 1000, and electricity market analysis. During the California Energy Crisis of 2001-2002, Mr. McMahon was a lead advisor to the California Department of Water Resources related to aspects of market restructuring, cost allocation, and revenue requirements determinations.

Experience

2013 - Present	*Vice President*, Charles River Associates – Energy Practice
2011 - 2016	*Board of Directors*, Pennichuck Water Works
2012 - 2014	*Director*, Black & Veatch - Management Consulting Division
2010 - 2012	*Vice President,* Siemens Corporation - Management Consulting Division
2009 - 2010	*Vice President,* Ascend Analytics
2007 - 2009	*Principal*, Charles River Associates
1998–2007	Navigant Consulting
	2007 *Director*, Energy Practice
	2005 - 2007 *Associate Director*, Energy Practice
	2003 - 2005 *Principal*, Energy Practice
	2002 - 2003 *Senior Engagement Manager*, Energy Practice
	1998 - 2002 *Senior Consultant*, Energy Practice

Selected Commercial Consulting Experience

For a utility with a significant coal portfolio, Mr. McMahon is leading the development of an integrated resource plan, including assumptions development, market modeling, stakeholder engagement, and report development.

For an IPP, Mr. McMahon led the annual valuation process for a combined cycle asset located in ERCOT that requires periodic mark-to-market valuation.

For an infrastructure fund, Mr. McMahon led a commercial analysis around a potential new combined cycle power plant development site located in PJM.

For an infrastructure fund, Mr. McMahon led a commercial analysis of the expected performance of a combined cycle power plant located in PJM, with consideration for a potential competitive generating asset development on the same price node.

For a turbine manufacturer and owner of power generation assets in the U.S., Mr. McMahon led a commercial analysis of the plants located in PJM.

For a utility with a significant coal portfolio, Mr. McMahon led an analysis of the company's generation options and how these options compared on a net present value revenue requirement basis across various scenarios.

For a utility that owned a portion of a nuclear power plant development impacted by the Westinghouse bankruptcy, Mr. McMahon led an engagement to analyze the methodologies and assumptions the company relied upon in their decision related to project completion or termination.

For an infrastructure fund, Mr. McMahon led the commercial due diligence around the fund's intended acquisition of a company that owns and operates waste-to-energy and simple cycle gas generating assets.

For an independent system operator, Mr. McMahon led an engagement focused on identifying best practices in competitive transmission procurement and how the ISO could become more efficient and quantitatively focused.

For an investment bank organizing a vehicle for a large industrial client to move deferred assets off the balance sheet, Mr. McMahon led the commercial due diligence around the expected performance of combined cycle power plants located across the U.S. and Canada tied to payments to the industrial through LTSA contracts.

For a large North American utility holding company, Mr. McMahon led a corporate portfolio strategy engagement focused on whether the company should consider diversifying away from electric and gas utilities toward midstream natural gas.

For an independent system operator, Mr. McMahon led an engagement to analyze the impact of a newly approved transmission project on the retail rates of customers in one particular state and how alternative cost allocation methods would impact rates.

For an integrated electric utility, Mr. McMahon led a project to develop bottom-up cost of service forecasts for 15 peer utilities in support of a client utility’s analysis of its investment headroom.

For an independent system operator, Mr. McMahon led an engagement to forecast transmission rates to different transmission regions and companies based on known and expected projects.

For an infrastructure investment fund, Mr. McMahon led a commercial due diligence engagement to support the fund's acquisition of a portfolio of combined cycle assets located in North Carolina and Ohio.

For three independent system operations separately, Mr. McMahon led multiple projects around competitive transmission solicitations to analyze bids on a cost of service basis and produce comparative analytics for the ISOs.

For an independent system operator, Mr. McMahon led an engagement to develop the framework and process for evaluating competitive transmission projects against the criteria specified by the system operator in its tariff.

For a Southeast utility with a significant coal-fired fleet, Mr. McMahon led the development of a carbon compliance strategy including physical and financial hedging, reallocation of capital and O&M between plants, and demonstration of customer rate impacts to policymakers.

For a large municipal utility, Mr. McMahon led an engagement to prepare a smart grid investment plan that was approved by the City Council.

For a Midwest utility, Mr. McMahon led an engagment to analyze and compare smart grid and traditional infrastructure replacement projects based on their impact on system reliability then support a program investment filing with the Commission.

For a Midwest utility, Mr. McMahon led the development of a $1.3 billion transmission and distribution replacement plan for filing with the state regulator, including enhancing the company's asset management program, analyzing the criticality of investment in classes of transmission and distribution assets, and preparing the regulatory filing and testimony.

For a large municipal utility, Mr. McMahon led an engagement to improve the resource planning and generation analytics capability, which included process development, considering new software and tools, and organizational realignment.

For a utility, Mr. McMahon led an engagement to support the shift to a new resource planning software, including training on applications and providing supporting analysis.

For a Midwest utility with a large coal portfolio, Mr. McMahon led an analysis of expected portfolio performance and consideration of alternative generation strategies, including portfolio divestiture and asset replacement.

For a Southwest utility with substantial coal assets, Mr. McMahon led an engagement to analyze how portfolios with varying amounts of coal performed under various future market conditions, and supported the company's resource plan with its regulator.

For a Midwest utility interested in expanding its regional footprint and taking advantage of Order 1000, Mr. McMahon led the development of a transmission strategy, including evaluating strategies of other transmission owners, analyzing the impact of investment on utility's rates, and developing recommendations for investment and partnership in MISO MVP projects.

For a utility attempting to optimize rate case timing as it relates to earnings, Mr. McMahon led a project to develop a detailed cost of service model to support a utility's strategic analysis of its capital investment, rate timing, and O&M spending options.

For a large generation and transmission cooperative facing rate pressures, Mr. McMahon supported the development of a strategy that reduced O&M costs and considered the impacts of future fuel costs on cooperative rates.

For a federally owned generation and transmission agency, Mr. McMahon analyzed alternative compliance options for the generation fleet with existing and expected environmental rules and how the company's fleet could comply overall at least cost.

For the State of California, Mr. McMahon led an engagement to develop a methodology for cost allocation of stranded costs and above market power costs related to the California Energy Crisis.

For the State of California, Mr. McMahon led an engagement to develop annual revenue requirements from 2002 to 2008 related to power costs incurred, and contracts entered into, during the California Energy Crisis.

Mr. McMahon led a generation strategy and integrated resource planning project on behalf of a Midwest utility that was considering significant portfolio changes including coal retirements and alternative capacity and energy additions.

Mr. McMahon led an initiative by a large utility holding company to consider alternative portfolio investments, including a natural gas midstream business.

Mr. McMahon led numerous projects on behalf of three RTO/ISOs to support procurement of competitive transmission under FERC Order 1000.

Mr. McMahon developed a carbon compliance strategy for a utility with a significant coal-fired fleet, including physical and financial hedging, reallocation of capital and O&M between plants, and demonstration of customer rate impacts to policymakers.

Mr. McMahon developed a resource strategy for an investor-owned utility with significant coal-fired assets and decreasing capacity factors, including evaluating net present value revenue requirements from alternative portfolios and developing real options analysis around retaining certain coal-fired assets and companion infrastructure.

Mr. McMahon developed a $1.3 billion transmission and distribution replacement plan for a Midwest investor-owned utility for filing with the state regulator, including enhancing the company's asset management program, analyzing the criticality of investment in classes of transmission and distribution assets, and preparing the regulatory filing and testimony.

Mr. McMahon developed a transmission strategy for an investor-owned utility interested in expanding regional footprint and taking advantage of Order 1000, including evaluating strategies of other transmission owners, analyzing the impact of investment on utility's rates, and developing recommendations for investment and partnership in MISO MVP projects.

Mr. McMahon led a project to evaluate the impact of a new combined cycle on nodal prices and assess the expected transmission interconnection costs for the development, including running detailed price simulations and evaluating market dynamics in PJM.

Mr. McMahon led a project to analyze whether a utility could acquire energy and capacity bilaterally, or whether the existing market was short capacity, including analyzing existing capacity in the market, new entrants, and potential counterparties.

Mr. McMahon supported the State of California to develop a methodology for cost allocation of stranded costs and above market power costs related to the California Energy Crisis.

Mr. McMahon supported the State of California in developing annual revenue requirements from 2002 to 2008 related to power costs incurred, and contracts entered into, during the California Energy Crisis.

Mr. McMahon led a project to develop a detailed cost of service model to support a utility's strategic analysis of its capital investment, rate timing, and O&M spending options.

Mr. McMahon led a project to develop bottom-up cost of service forecasts for 15 peer utilities in support of a client utility's analysis of its investment headroom.

Filed Testimony

Comments of FirstEnergy Service Company, Docket No. RM18-1-000. Affidavit in support of Comments by FirstEnergy Service Company, related to the Department of Energy Notice of Proposed Rule on Grid Resiliency before the Federal Energy Regulatory Commission. October 2017.

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Reports and Publications

"*Migration to Midstream: Strategic Considerations for Utilities Investing in Midstream Assets*", CRA Insights, August 2017

"*Emerging Issues in Electric Utility M&A*", CRA Insights, January 2017

"*The Growing Risks of Regulated Coal Ownership*", CRA Insights, May 2016

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"*Why Utilities Need to Rethink Their Capital Programs: What Went Wrong in Indiana*", CRA Insights, June 2015

"*The Distributed Resource Plan*", CRA Insights, February 2015

"*An Uptick in Recent Electric Utility - Gas Utility Mergers. Expect More*", Energy Bar Association, Litigation Journal, fall 2015, Vol. 15 No. 1

"*Latent Risks in Utility M&A*", CRA Insights, May 2014

"*Risk Based Asset Investment Approaches to Improve System Resiliency*", Black & Veatch, September 2013

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"*Improving Capital Planning Process in Light of Today's Capital Crisis*", CRA Insights, January 2009

"*Valuation of Generation Assets: Why Modeling Matters*", CRA Insights, September 2008

"*Potential for Coal Plants' Hidden Value in a World of Carbon Costs*", CRA Insights, December 2007

Presentations

Finding Investment Headroom in a Rising Rate Environment, CRA Webinar, March 21, 2017

Utility M&A Finding Investment Headroom in a Rising Rate Environment, S&P Power and Gas M&A Symposium , February 14, 2017

Clean Power Plan: Perspectives on Utility Strategy, SNL Energy Webinar Series, January 13, 2016

Financial and Regulatory Challenges in Screening Utility M&A Targets, CRA Webinar, Oct 2016

Changing Energy Markets and the Evolving Generation Fleet, Utility Commissioners/ Wall Street Dialogue, May 10, 2016

Clean Power Plan: Implications for Utility Generation Strategy, EEI Strategic Issues Roundtable, September 30, 2015

Natural Gas Market Update: New England, Law Seminar International, August 27, 2014

Building a T&D Investment Program to Satisfy Utility Customers, Regulators, and Shareholders, SNL Energy Webinar Series, March 27, 2014

Sustainable Earnings Growth through Electric Utility Investment, EEI Strategic Issues Roundtable, October 9, 2013

Back to the Future or Back to the Past, EEI Strategic Issues Roundtable, February 18, 2011

How Social Media Impacts Customer Relationship Management and the Utility's Bottom Line, EEI Strategic Issues Roundtable, October 21, 2010

PUBLIC VERSION

Generation Fleet Savings Analysis

The Empire District Electric Company

October 2017

****Denotes Confidential****

PUBLIC VERSION

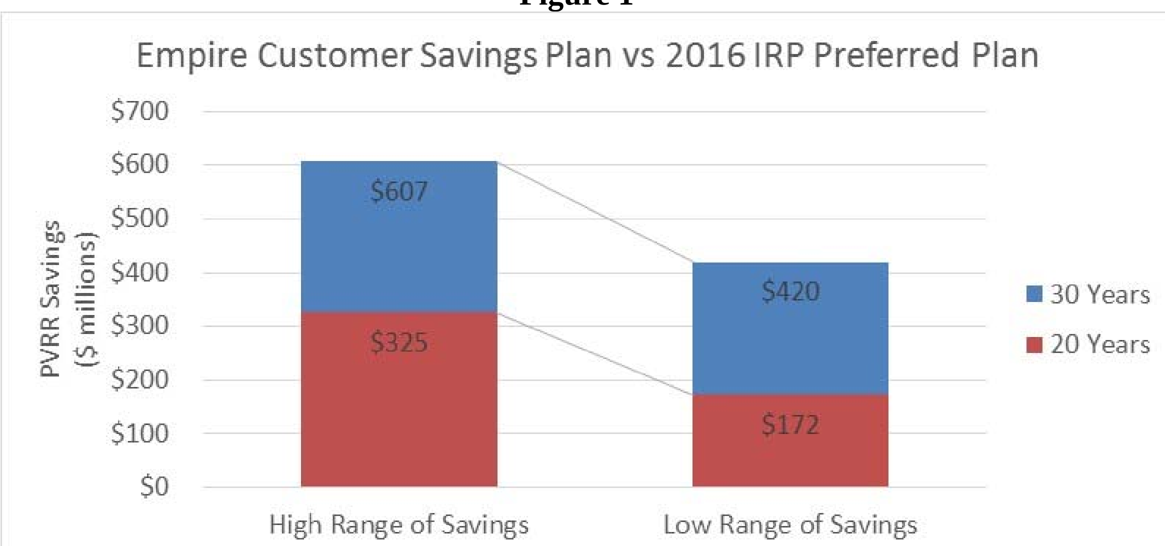
Table of Contents

Generation Fleet Savings Analysis

1. Executive Summary

The Empire District Electric Company (Empire or Company) is at a pivotal point in its history regarding the options available to generate electricity to serve its customers. Declining costs of renewable generation, the availability of federal tax incentives to encourage their development, and changes in market prices in the industry are driving changes in how electric utilities like Empire can supply their customers. In response to these industry shifts, Empire undertook an analysis to consider whether there are savings it can deliver to customers over and above its 2016 Integrated Resource Plan ("2016 IRP") using federal tax credits in conjunction with a tax equity partner in the development of renewable generation. This analysis, called the "Generation Fleet Savings Analysis" or the "GFSA" demonstrates that with updates to three key factors to the 2016 IRP, substantial savings can be delivered to customers. Specifically, the Generation Fleet Savings Analysis shows that by adding up to 800 MW of new, utility owned wind that is strategically located in or near Empire's service territory and retiring the Asbury generation facility by the spring of 2019, and establishing a regulatory asset to recover a return on and of the remaining net book balances of the plant, customers' bills will be reduced by $172 million to $325 million over the next twenty years, or $420 to $607 million over the next 30 years compared to the current plan[1]. These results, shown in Figure 1 below, are striking and present a unique opportunity to save customers substantially in decades to come.

Figure 1



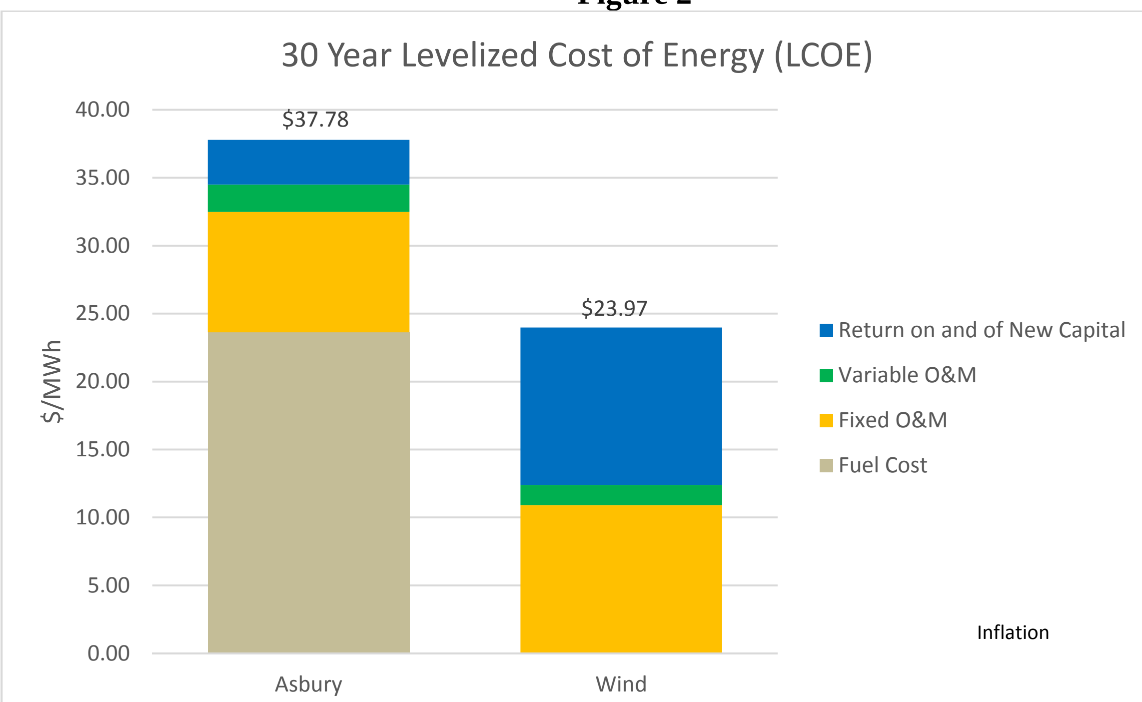
[1] Calculated on a Net Present Value Revenue Requirement ("NPVRR") basis.

These savings are driven by the following three key updates to the 2016 IRP:

- The production cost model was updated to include nodal market prices to reflect the Southwest Power Pool Integrated Marketplace ("SPP IM"). The 2016 IRP used zonal price modeling methodology.
- The capital cost of renewable energy projects was reduced to reflect the significantly declines since the 2016 IRP, particularly when incorporating the effects of tax equity financing.
- The expected performance of wind farm technology was updated to reflect the rapid improvements in wind turbine technology which is the result of larger rotor diameters in lower wind speed regions.

The Generation Fleet Savings Analysis revealed is significant customer savings can be achieved by acquiring wind generation versus continued operation of the Asbury coal plant. This is in part because wind, on a levelized cost basis, is approximately $14 per megawatt hour cheaper than Asbury for customers, as shown in Figure 2:

Figure 2



Part of the reason that wind generation is able to deliver these savings is because of the ability to partner with tax equity. This financing tool allows Empire to join forces with a tax equity partner to maximize Production Tax Credits ("PTCs") and other tax attributes to lower the cost of the potential projects to Empire's customers. PTCs are available under U.S. tax law now but will be reduced by 20% per year for projects placed in service after 2020. Thus, there is a limited window of time to take advantage of these tax benefits.

These tax benefits allow for the more efficient monetization of the tax attributes associated with renewable energy projects. As a simple example, a $100 million generation asset can be placed into rate base at only $40 million when partnering with tax equity, thereby delivering significant savings to customers.

Use of the tax equity model is not new to Empire's parent, Algonquin Power & Utilities Corp. (Algonquin). Algonquin has developed over 900 MW of renewable generation in the United States with tax equity partners. Liberty Utilities (CalPeco Electric) LLC, an Empire affiliate that provides retail electric service in California, recently added 50 MW of tax equity financed solar generation, a project that was fully reviewed and approved by the California Public Utilities Commission (CPUC). Liberty CalPeco currently has another application before the CPUC for the development of an additional 10 MW of solar generation for the benefit of its customers. By completing this Generation Fleet Savings Analysis, Empire would like to bring those same opportunities to save money to its customers. The concepts of developing utility owned renewable generation to lower customer bills are not new to the electric utility sector. Xcel Energy, American Electric Power, Rocky Mountain Power and NextEra Energy, among others, are pursuing similar programs.

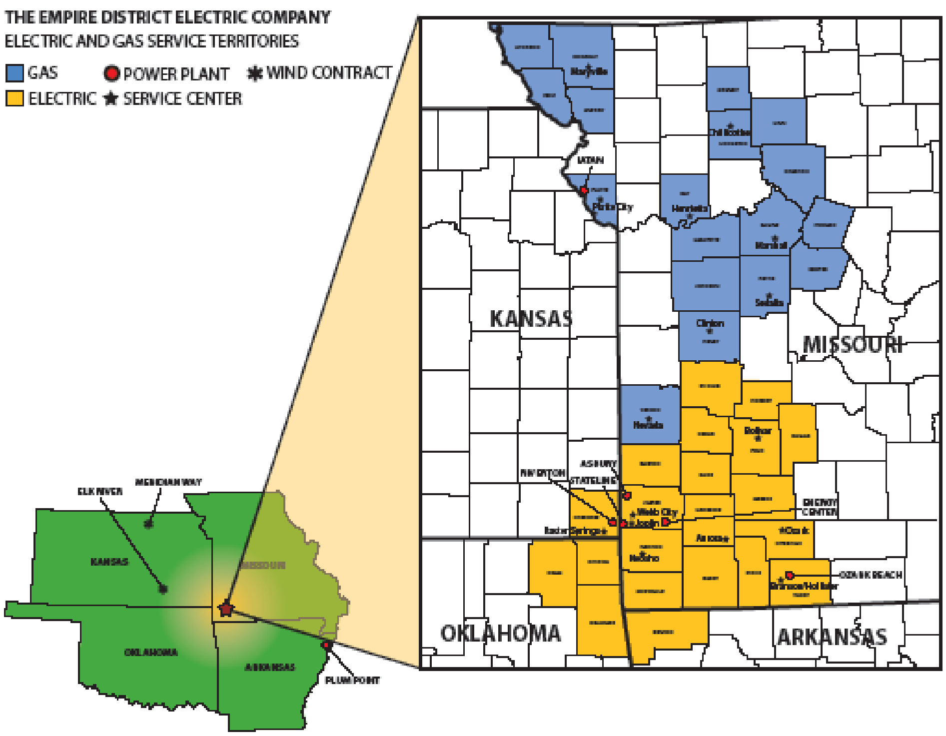
Savings in the Generation Fleet Savings Analysis are also driven by the retirement of the Asbury coal plant. Approximately $20 to $30 million is needed by 2019 to install a dry bottom ash conveyor and a new ash landfill, all to ensure continued compliance with the Coal Combustion Residual (CCR) rule and the Effluent Limitation Guidelines (ELG). Empire believes it is in its customers' best interests to avoid this cost and to begin to transition to a cheaper and cleaner future. The Generation Fleet Savings Analysis assumes that in conjunction with the acquisition of up to 800 MW of wind generation, Empire would recover a return on and of the remaining net book value of Asbury (approximately $200 million). This is important to ensure the Company is made whole on its investment and avoids potential stranded cost issues, while at the same time lowering customers' bills.

In sum, the Generation Fleet Savings Analysis demonstrates that with the acquisition of up to 800 MW of strategically located wind in or near Empire's service territory, and the retirement of Asbury and the establishment of a regulatory asset to recover the return on and of its net book value, customers can save hundreds of millions of dollars over years to come.

2. Introduction

a. Background on Empire

Empire is engaged in the generation, purchase, transmission, distribution and sale of electricity to over 170,000 electric customers in parts of Missouri (88.8%), Kansas (4.7%), Oklahoma (3.1%) and Arkansas (3.4%). Empire's electric service territory includes an area of about 10,000 square miles with a population of over 450,000. The electric service territory is located principally in southwestern Missouri and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal activities of these areas include light industry, agriculture and tourism. The following depicts Empire's service territory:



Empire supplies electric service at retail to 119 incorporated communities and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area served is the city of Joplin, Missouri (population approximately 50,000), and its immediate vicinity, with a regional population including Joplin of approximately 160,000. Empire's system maximum hourly demand for 2016 was 1,114 MW which occurred on December 19, 2016. The all-time maximum hourly demand of 1,199 MW occurred on January 8, 2010. Empire's 2016 native customer load was 5,290,273 MWh. Empire's electric operating revenues in 2016 were derived as follows: residential 43.6%, commercial 31.7%, industrial 15.9%, wholesale on-system 3.6%, and other 5.1%.

Empire serves parts of twenty-one counties: sixteen (16) in Missouri, one (1) in Kansas, three (3) in Oklahoma and one (1) in Arkansas, as shown in Table 1.

Table 1
Counties in Empire's Electric Service Territory

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

Empire Generating Facilities

Empire owns and operates a diverse generating portfolio that includes wholly-owned units, jointly-owned units and power purchase agreements (PPA). The units operate on coal, natural gas, fuel oil (as a secondary fuel), hydro and wind as can be seen in Table 2 and Figure , and Figure 4 depicts the generation mix (where the energy came from) by type for 2016. These data represent the Empire capacity mix.

Table 2
Generating Resource by Type - 2016

Type	Capacity (MW)	%
Owned Coal	434	25.67%
Coal PPA	50	2.96%
Natural Gas	936	55.35%
Hydro	16	0.95%
Wind PPA	255	15.08%
Total	**1,691**	**100.00%**
Notes: Wind is nameplate capacity, not accredited capacity. Utilizes summer ratings		

Figure 3
2016 Capacity Mix (Nameplate)

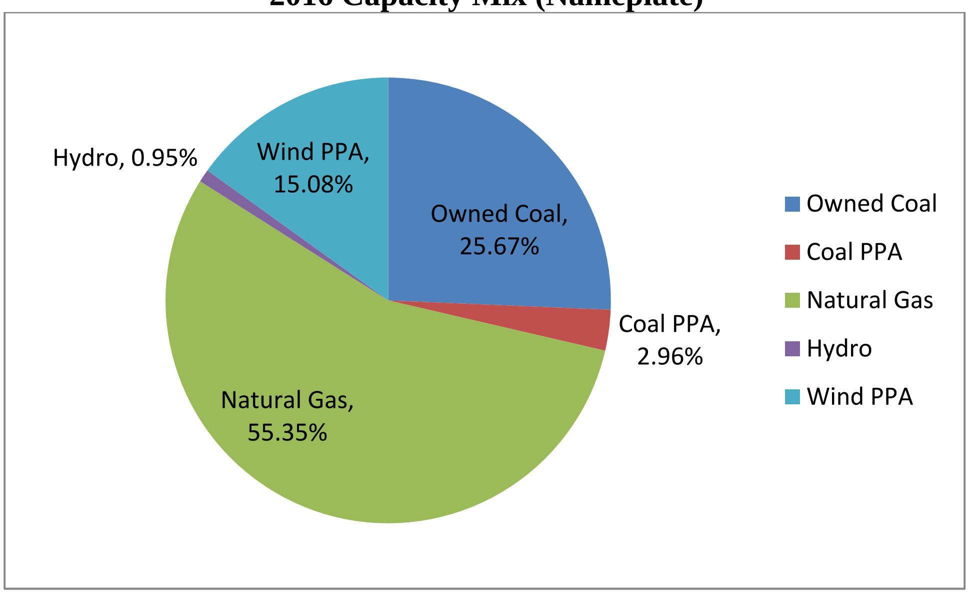
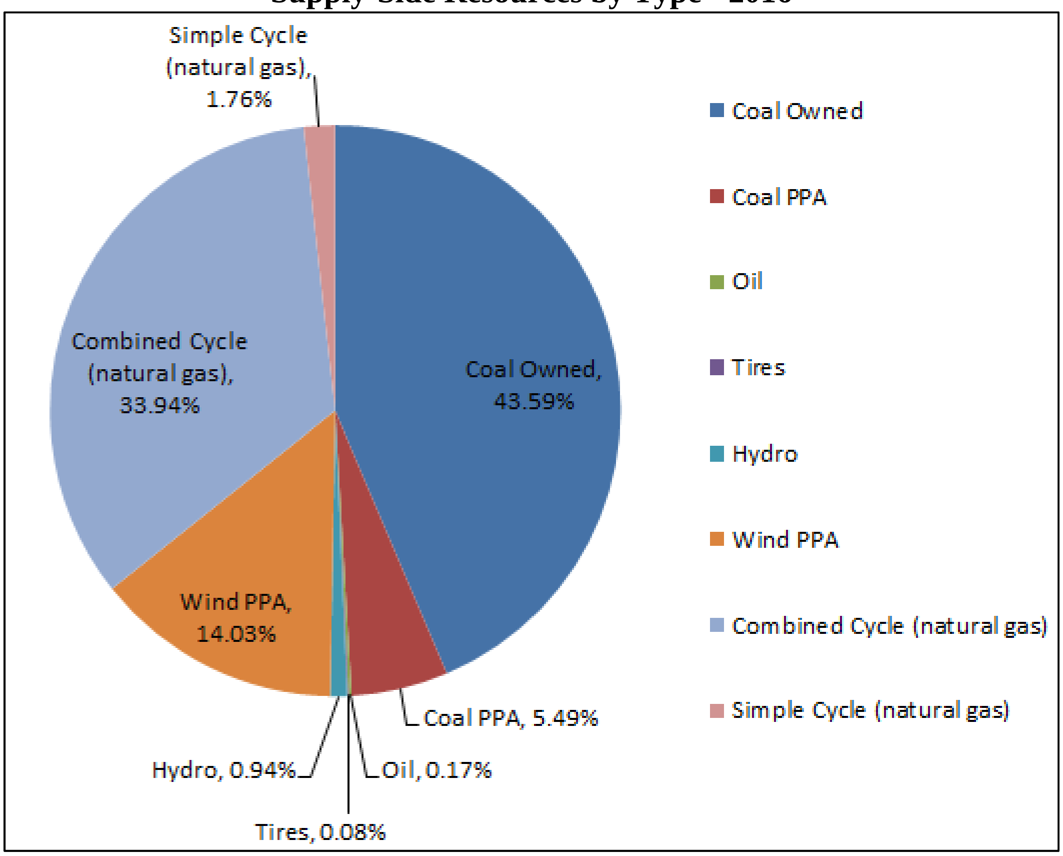


Table 3
Existing Supply-Side Resources – 2016

Type	MWh	%
Coal Owned	2,562,113	43.59%
Coal PPA	322,788	5.49%
(Total Coal (Own + PPA) = 49.09%)		
Oil	9,924	0.17%
Tires	4,531	0.08%
Hydro	55,294	0.94%
Wind PPA	824,422	14.03%
Combined Cycle (natural gas)	1,994,520	33.94%
Simple Cycle (natural gas)	103,725	1.76%
(Total Natural Gas (CC + SC) = 35.70%)		
Total MWh EDE Resource	**5,877,318**	**100.00%**

Figure 4
Supply-Side Resources by Type - 2016



Existing Demand-Side Resources
At one time, Empire offered a demand-side portfolio in each of its four states, but at the time of this filing, Empire only offers demand-side programs in Missouri and Arkansas. Customer programs began in Missouri in mid-2007 and in Arkansas in October 2007. Customer programs that began in Oklahoma in 2010 were discontinued on May 1, 2014 (Order No. 624718 in Oklahoma PUC Cause No. PUD 201300203), and the three-year Kansas pilot program that began in in June 2010 concluded in June 2013. The current Missouri and Arkansas programs are shown in Table 4 below. Although the 2016 IRP Preferred Plan did not include any energy efficiency programs, Empire agreed in its last Missouri rate case (File No. ER-2016-0023) to provide a few of the programs studied in the 2016 IRP. In addition, Empire currently has an Energy Efficiency Cost Recovery rider in Arkansas, which was designed to recover the full cost of implementing energy efficiency programs with a rate that is reconfigured annually. Empire does not have such a mechanism in Missouri, recovering energy efficiency costs through base rates.

Table 4
Demand-Side Programs by State

Missouri	Arkansas
● High Efficiency Air Conditioner Rebate Program	● Arkansas Weatherization (Empire Contractor Program)
● Multi-Family Direct Install	● High-efficiency Residential Lighting (LED)
● Income-Eligible Multi-Family Direct Install	● School-Based Energy Education
● Commercial and Industrial Rebate Program	● Commercial and Industrial Rebate Program
● Low-Income Weatherization	

b. Empire's IRP Process

The IRP planning process consists of a comprehensive study performed in collaboration with Missouri stakeholders every three years. Annual reports are issued in the intervening years evaluating changes to critical uncertain factors and discussed with stakeholders in an annual workshop. This process is performed in accordance with the requirements defined in Chapter 22 of the MPSC rules (4 CSR 240-22.010 – 240-22.080). The IRP is also sent to Arkansas, Kansas, and Oklahoma for review. Empire's most recent Integrated Resource Plan was completed in 2016 and submitted in Missouri Public Service Commission ("MPSC") File No. EO-2016-0223 on April 1, 2016 (2016 IRP). On April 4, 2017 the MPSC issued an order stating the 2016 IRP complies with Chapter 22 of the MPSC rules (4 CSR 240-22.010 – 240-22.080) ("IRP Rule"). In addition, the 2016 IRP was submitted to the Kansas Corporation Commission in April 2016, the Arkansas Public Service Commission in March 2017, and the Oklahoma Corporation Commission in June 2017.

Since the 2016 IRP study was performed, there have been three important changes that affect the IRP study results and have caused Empire to undertake this Generation Fleet Savings Analysis:

1) This is the first IRP modelling completed by Empire incorporating the SPP Integrated Marketplace. This changes the nature of the buying and selling of energy and allows for different optimization of Empire's generation sales and load purchases;
2) Continued downward trends in the pricing of renewables, extension of the PTCs and availability of tax equity financing. In combination, wind had the lowest cost per kW installed out of all technologies available. The PTCs sundown dates create a sense of urgency to ensure that Empire's customers can realize this limited benefit; and
3) Continued improvements in wind turbine technology leading to improvements in efficiency. Higher hub heights and larger rotor diameters have led to significant improvements in energy production in lower wind speed areas that were previously uneconomic, such as Empire's service territory.

ABB was engaged to provide modeling and analytical services to assist with a study evaluating a least cost portfolio for our customers including additional wind resources and optimized retirement of existing units. The 2016 IRP assumptions vetted through the stakeholder process were utilized as the foundation of the GFSA model and updated to the three key changes discussed above.

3. Modeling Overview

Empire engaged ABB, the consultant utilized to model its last several IRP studies, to provide modeling and analytical services to assist with this Generation Fleet Savings Analysis evaluating the least cost portfolio for customers including additional wind resources and optimized retirement of existing units. The Generation Fleet Savings Analysis utilized Empire's 2016 IRP model as a starting point to take advantage of previous stakeholder input and review regarding base assumptions for load, supply-side resources, demand-side resources, and other inputs. Details regarding updates to the 2016 assumptions will be discussed in Section 5: Assumptions and Model Input Changes.

ABB utilized its integrated suite of market and portfolio models, called Capacity Expansion and Strategic Planning to simulate the SPP IM, screen the resource alternatives, and perform operational and financial analysis of the Empire portfolio.

Empire participates in the SPP IM to meet its customers' energy and ancillary service requirements. In Empire's 2016 IRP, a zonal market structure was used in the modeling due to a limited amount of data available for the SPP IM at the time the model was developed. Approximately three years of SPP IM operational data was available at the start of the GFSA allowing the 2016 IRP model to be updated to utilize a nodal market and more accurately reflect generation revenue and load expense expectations based on nodal market prices. The study period was 2018-2047, which compared to the 2016 IRP study period of 2016-2035.

ABB and Empire determined several scenarios were necessary to evaluate a range of potential outcomes to determine the least cost portfolio. In addition to utilizing the assumptions underlying the Preferred Plan from the 2016 IRP, high and low gas scenarios were included to account for potential changes to the natural gas market. Scenarios to evaluate different locations and capacity levels of wind were included to study the impact of market price basis in relation to wind resource locations. Nine total scenarios were modeled.

The nine scenarios were developed to evaluate various levels of wind capacity added, as well as the impact of the location of additional wind. As will be discussed in later sections, transmission constraints and considerations were modeled utilizing market price basis differentials based upon location. The maximum total wind capacity allowed to serve Empire native customer load in the model was 1,100 MW, including existing wind resources, which allowed 845 MW of new wind in the study and kept the total nameplate of wind capacity below the projected customer peak load.

Figure 5
Modeled Scenarios

Benchmark – Plan 1 - 2016 Base Plan
• Included RAP Portfolio DSM in load forecast
• This was the Preferred Plan in the 2016 IRP and identified wind generation acquisition in 2029.
Plan 2 – 2017 Base Plan – Plan 2 (Base 800 MW Low LCOE Wind)
• Base Assumptions
• Total new wind limit 845 MW
Plan 3 - 2017 Low Savings Range (400 MW low LCOE wind & 400 MW mid LCOE wind)
• Base Assumptions
• Low LCOE Wind Limit of 400 MW
Plan 4 – 2017 Base with No Asbury Retirement (Base with Asbury)
• Base assumptions
• No Asbury Retirement in 2018
Plan 5 - High Gas Price (High Fuel)
• Base assumptions
• High Gas/Market Prices
Plan 6 - Low Gas Price (Low Fuel)
• Base assumptions
• Low Gas/Market Prices
Plan 7 - Low and Mid LCOE Wind Limited to 300 MW
• Base Assumptions
• Low and Mid LCOE Wind Limit of 300 MW
Plan 8 - Low and Mid LCOE Wind Limited to 200 MW
• Base Assumptions
• Low and Mid LCOE Wind Limit of 200 MW
Plan 9 - Low and Mid LCOE Wind Limited to 200 MW + No Solar
• Base Assumptions
• Low and Mid LCOE Wind Limit of 200
• No Solar

The nine scenarios were modeled in the Capacity Expansion Module (CEM) to identify the optimal timing of resource investments and retirements, and sales and purchase to meet the Empire demand. The Empire demand reflects the demand-side (DSM) alternatives that passed the Applied Energy Group (AEG) screening tests from the 2016 Integrated Resource Plan (IRP).[1] These Realistic Achievable Potential (RAP) candidates were modeled in the CEM as modifications to the load forecast[2]. The CEM optimized supply-side resources around the demand-side resource modified load completely enumerating all possible supply-side combinations using mixed integer linear programming (MILP). The objective of the optimization is to minimize the present value of revenue requirements (PVRR), while maintaining a 12% capacity margin (equivalent to a 13.6% reserve margin)[3].

The following is a list of base assumptions used in the GFSA:

- RAP Portfolio DSM
- 845 MW additional wind capacity limit
- Reference Case Base Gas, Market and Emission Prices
- No carbon pricing
- Renewable energy meets state RPS (15%)
- Retire Energy Center Unit 1 ("EC 1") December 2022
- Retire Energy Center Unit 2 ("EC 2") December 2025
- Retire Riverton Units 10 & 11 ("Riv 10", "Riv 11") December 2032
- Allow model to retire Asbury Unit 1 in December 2018
- Allow model to retire Energy Center 1-4 starting in 2020
- Meridian Way contract expires 12/23/28
- Elk River Extension through 12/15/2030
- Renewable Options: Wind, Biomass, Landfill Gas, Solar, Battery
- Other Supply-side Alternatives: Same as 2016 IRP[4] with IC engine updates
- Gas Transportation cost per 100 MW for new technologies:
  - $2.3 million for Combined Cycle ("CC")
  - $3.5 million for Combustion Turbine ("CT")
- Mid LCOE Wind
  - Defined as projects with basis similar to Asbury and minimal transmission upgrade requirements. Wind estimates based on mesoscale data for the Empire service territory.
- Low LCOE Wind
  - Defined as projects with basis similar to Elk River. Projects are assumed to have meaningful transmission.

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[1] 2016 IRP Vol. 5, Appendix 5A, and Appendix 5B
[2] The RAP DSM portfolio was included in the 2016 IRP Preferred Plan for this study in order to maintain an equivalent basis.
[3] SPP has recently changed the requirement for the reserve margin to be 12%, down from the prior 13.6%.
[4] 2016 IRP Vol. 5

Table 5 summarizes the optimal supply side resource expansion plans, with the base assumptions listed above, produced by the CEM.

Table 5
Optimal Expansion Plans

	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6	Plan 7	Plan 8	Plan 9
YEAR	Preferred Plan 5 from 2016 IRP	Base - 845 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 RetireEC2	100 MW CC Retire C2
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					

After the CEM module determines the optimized portfolio set under each of the nine scenarios, the Strategic Planning module is run to evaluate the financial and rate impacts for each portfolio. Strategic Planning evaluates how each portfolio performs against a detailed representation of the markets in which each plant in the portfolio operates. ABB inputs the detailed operating characteristics of the Empire fleet into Strategic Planning and performs deterministic, scenario and uncertainty simulations to assess the performance associated with each plan. ABB also forecast retail rate impacts of each plan for each sensitivity assuming perfect ratemaking[5].

4. Assumptions and Model Inputs Changes

As discussed in the previous section, the 2016 IRP Preferred Plan was utilized as the starting point for the model built for the Generation Fleet Savings Analysis. 6 outlines the major assumptions that were updated:

[5] Note, the Strategic Planning module is calibrated to match Empire's financial projections from the 2016 IRP and performed annual rate making to meet return on rate base.

Table 6

2016 IRP Plan	Generation Fleet Savings Analysis
Modeled as individual balancing authority and zonal market.	Modeled SPP IM and nodal market.
No DSM.	RAP Portfolio DSM.
ABB Spring 2015 Reference Case Base Gas, Market and Emission Prices.	ABB Fall 2016 Reference Case Base Gas, Market and Emission Prices.
Renewable energy meets RPS.	Same.
Retire Riverton 10 & 11 no later than the end of 2032.	Same.
Retire Energy Center Unit 1 no later than the end of 2022 and Unit 2 no later than the end of 2025.	Same.
Retire Asbury in 2035.	Allow model to retire Asbury when prudent.
Allow model to retire Energy Center 1-4 starting in 2020.	Same.
Meridian Way contract expires 12/23/28.	Same.
Elk River Extension through 12/15/2030.	Same.
Renewable Options: Wind, Biomass, Landfill Gas, Solar, Battery.	Same except wind pricing and performance and solar pricing and performance.
Gas Transportation cost per 100 MW for new technologies: $2.3 million for CC; $3.5 million for CT.	Same.
Carbon Pricing included beginning 2022.	No carbon pricing.

Southwest Power Pool Integrated Marketplace

Participation in the SPP IM has been the most significant change to Empire's generation operations from a unit dispatching perspective in the past few years. During the development of the 2016 IRP, it was determined not enough market information was available to effectively model a nodal market place. With approximately three years of data available for this study, the model was updated to simulate a nodal market. Prices for all Empire generation and load locations were developed by applying historical basis factors to the 2016 Fall Reference Case market price forecasts for the SPP KS-MO zone.

Demand-Side Resources

The Generation Fleet Savings Analysis utilized the Realistically Achievable Potential (RAP) portfolio from the 2016 IRP for the demand-side assumptions. For more information regarding these assumptions please see the 2016 IRP Vol. 5.

Fuel and Market Prices

The Generation Fleet Savings Analysis utilized the ABB 2016 Fall Reference Case market price forecasts for the SPP KS-MO zone. As reported in the 2017 IRP Annual Update filed in EO-2017-0223, the 2016 Fall reference case indicates a 10% lower forecast than was utilized in the 2016 IRP.

Henry Hub Natural Gas

The Generation Fleet Savings Analysis relied on the ABB Fall 2016 Fall Reference Case for the forecasted Henry Hub gas price forecast. According to ABB, the forecasted increase in natural gas prices after 2020 is attributed to several factors including demand growth from industrial users, expected increases in LNG exports, pipeline exports to Mexico, and power demand. Power demand is expected to increase primarily due to the increase in natural gas plants as coal and nuclear facilities are retired. These demands are predicted to overcome lower load growth projections. Annual prices are shown in
Figure 6. A table of values can be viewed in Appendix 1.

Figure 6
Annual Henry Hub Natural Gas Forecast for all Scenarios (Nominal $/MMBtu)
****Confidential in its entirety****

(Source: ABB Advisors.)

Empire natural gas generation units are served on the Southern Star pipeline. In addition to the Henry Hub gas price, a Southern Star adjustment is added to the monthly Henry Hub price. A losses and commodity charge is also added to the monthly price.

Market Price Forecast

SPP-KSMO market prices were utilized from the ABB Fall 2016 Midwest Power Reference Case. Figure 7 illustrates Empire's Monthly 7x24 (average) price forecast for the base, high and low gas, and carbon tax scenarios. Appendix 1 includes the 7 x 24 annual market prices for the same scenarios.

Figure 7
SPP-KSMO 7x24 Market Prices for All Scenarios (Nominal $/MWh)
****Confidential in its entirety****

(Source: ABB Advisors.)

To simulate the SPP IM and obtain a nodal solution, ABB started with the zonal SPP-KSMO market prices from ABB's 2016 Fall Reference Case then applied a monthly spread to the zonal price to create nodal prices. The monthly spread was based on 2016 historical average differences between the actual zonal and nodal points of interest to the prices.

Each hourly historical LMP price node is divided by the historical Empire LMP in order to create an hourly multiplier and then the hourly multipliers are averaged in order to create a multiplier for each month. The monthly multipliers are then applied to the ABB forecasted base case market prices for the SPP-KSMO region to develop unique 8,760 hourly price strips that represent Empire's different price nodes within the SPP IM.

Empire utilized historical day-ahead Location Marginal Prices (LMP) from each of the following price nodes to develop basis adjustments: Asbury, Iatan, Plum Point, Energy Center 1 and 2, Energy Center 3 and 4, Riverton 12 CC, State Line 1, SLCC, Ozark Beach, Elk River, Meridian Way, and the EDE load area. This is important due to the location of Empire's generation resources throughout the SPP IM footprint which are affected by transmission congestion and loss components.

Coal Price Forecast

The coal price forecasts used for the Asbury, Iatan, and Plum Point facilities were supplied by Empire through 2021. After 2021, annual escalation was based on ABB's average delivered coal price for SPP-KSMO projections. Base coal price projections for Empire's coal units are in Appendix 1. This is an update to the 2016 IRP which relied upon the Energy Information Administration inflation projections.

Load Forecast

Load forecasts have remained largely unchanged since the 2016 IRP Reference case. Increased energy efficiency trends have tempered expected gains from increased customer counts. As a result, no updates were made to the model for the Generation Fleet Savings Analysis. Detailed information related to the load forecast can be found in the 2016 IRP Volume 3 and 3A.

Cost of Capital Assumptions

The completion of the acquisition of Empire by Liberty Utilities necessitated an examination of the cost of capital assumptions utilized in the 2016 IRP.

The updates to capital structure of new investments in the GFSA are shown in the Table 7.

Table 7

	2016 IRP	Generation Fleet Savings Analysis
Debt Rate	5.65%	4%
Return on Equity	10%	Same
Debt to Equity	49:51	Same

The new debt rate was based on Liberty Utilities' latest debt issuance after the acquisition of Empire. The Generation Fleet Savings Analysis did not make changes to the debt rate already issued for prior investments.

Capital Expenditure Assumptions

No changes to capital expenditures were made to the existing generating assets from the 2016 IRP, with the exception of the Asbury assumptions described in the Asbury Retirement section below. The primary Asbury capital expenditures are related to a dry bottom ash system, a new ash landfill and other minor ongoing capital obligations.

Supply-Side Resources

The 2016 IRP supply side assumptions were utilized for the GFSA with the exception of Asbury costs, wind resource additions, tax equity structures, and unit retirement dates described below. All other supply-side inputs and assumptions can be reviewed in the 2016 IRP Vol. 5 and Appendices 5A and 5B.

Asbury Retirement

Updates were made to allow the model to determine if it was more cost effective to repower or retire Asbury beginning in December of 2018. For Asbury to be compliant with the Coal Combustion Residual (CCR) rule and the Effluent Limitation Guidelines (ELG), Asbury needs to complete two significant capital projects by April 2019: 1) a dry bottom ash conveyor, and 2) a new ash landfill. The model included the option to continue operation of Asbury by spending the 2018 present value of the aforementioned capital projects in addition to the reasonably foreseeable maintenance capital expenses required for Asbury to operate until 2035. Table 8 lists the capital cost assumptions that were included in the model for the repowering option:

Table 8
Asbury Ongoing Capital Requirements

Time Frame	Category	Cost	Description
2017 to 2018 (~$24M)	Dry Bottom Ash Conversion	$13.0 million	The Effluent Limitation Guidelines (ELG) requires Asbury to eliminate the use of water to transport ash to ash storage ponds. The dry bottom ash project will allow the bottom ash to be transported dry to a new dry ash landfill.
	New Ash Landfill Project	$5.7 million	The Coal Combustion Residual (CCR) rule requires the closure of the existing ash pond landfills at Asbury. It was determined that building a new landfill adjacent to Asbury would cost less money than shipping the ash offsite. The landfill will be built in phases over the remaining life of Asbury.
	Boiler tube and furnace replacements part 1	$2.1 million	A non-recurring boiler tube and furnace replacement is required in 2018 and 2019 to allow Asbury to operate for more than 5 years.
	Other Projects	$3.4 million	Smaller projects spread over multiple categories: Plant replacements and improvements; high energy piping; coal handling system additions; duct work, deep well pump & column; plant upgrades.
2019 to 2021 (~$10M)	Air Quality Control System (AQCS)	$2.9 million	Capital work is required on the bag house and scrubber of the AQCS. The Selective Catalytic Converter (SCR) will also need replacing every 3 to 5 years at a cost of approximately $1 million.
	Boiler tube and furnace replacements part 2	$2.3 million	A non-recurring boiler tube and furnace replacement is required in 2018 and 2019 to allow Asbury to operate for more than 5 years.
	Other Projects	$4.4 million	Smaller projects spread over multiple categories: Plant replacements and improvements; coal handling system additions; high energy piping; turbine generator and auxiliaries; plant upgrades; cooling tower; and incidental replacements.
2022 to 2035 (~$12M)			In this longer term capital forecast, Empire focused on reasonably predictable recurring costs and attempted to under estimate rather than over estimate.
	AQCS and SCR	NPV $5.9 million	Assumed bag house and scrubber in 2025 and 2030 at $1.5 million. Assumed SCR at $1.2 million in 2024 and 2029 and $1 million in 2033.
	New Landfill Cell 1B	NPV $3.2 million	Cell 1A of the new landfill is expected to be full by 2029 at which time Cell 1B must be placed in service.
	Furnace replacements	NPV $1.5 million	Assumed $800k in 2026 and 2032.
	Other Power Plant Upgrades	NPV $0.8M	Miscellaneous upgrades and replacements at $150k every two years.
	High energy piping system	$0.5M	$85k every 2 years, which is half of the current spend rate.

The fixed operating cost assumptions for Asbury took the 2017 5-year forecast and annually escalated them at 3%. The inflation rate was based upon presumed increases associated with the large amount of labor in Asbury operating costs and the maintenance and train costs which are expected to continue to see increased upward price pressures.

In the model selected to retire Asbury in 2018, the following assumptions were made:

- Establishing a Regulatory Asset of $206.6[6] million amortized over 30 years, which lines up with the planned life of the wind assets; and
- Decommissioning costs of $27 million less $12 million in salvage for a net decommissioning cost of $14.6 million
    - Decommissioning estimates were created during the 2016 IRP and updated for a 2018 retirement date. Empire believes that the costs allocated to decommissioning are reasonable based on recent work being completed at Riverton.

After the modeling was completed, Empire determined that compliance with the ELG and CCR rules could be extended to April 2019, rather than October 2018 as assumed in the model. Since the early retirement scenario is tied to the capital associated with those rules, it is expected that the actual retirement date in that scenario will be April 2019. There will not be a material difference in modeling based on the difference between October 2018 and April 2019.

Wind Power Assumptions

The overall performance of utility scale wind turbines has improved dramatically over the past several years. At the same time, capital and operating costs for this equipment have improved, resulting in significant, real reductions in the cost of energy. Increased tower heights, improved power capture efficiency, and more effective blade configurations are just a few of the enhancements that have allowed greater wind performance and increased capacity factors in areas not previously considered advantageous for wind generation. In addition to absolute cost and performance improvements, wind turbine manufacturers have had considerable success in the development of equipment capable of providing high capacity factor output levels in moderate wind resource areas. These advances make the use of wind turbines technically and financially competitive with more traditional forms of generation.

In addition, the extension of the renewable generation tax incentive programs by the federal government provide certainty for utilities wishing to deploy wind turbine technology. While the tax incentive programs currently in place are not new, historically, Congress has not provided long term stability for these programs. With the extension of the PTC program, passed by Congress in late 2015, Empire is able to prudently plan to take advantage of these incentives for the benefit of its customers before the plans are discontinued.

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[6] This is higher than the amount referenced above due to timing of December 2018 versus projecting to retirement in April 2019.

Finally, Empire is able to take advantage of APUC and Liberty Utilities' expertise and experience in deploying tax equity financing to support the development of renewable generation technology.

For the purposes of the Generation Fleet Savings Analysis, Empire has approached the evaluation of utility scale wind generation by reflecting the advances identified above, combined with reasonable assumptions regarding site specific factors, in two generic wind projects. The generic wind projects provide a realistic view of the overall cost and performance of wind projects that can be used to provide Empire's customers with low cost and reliable energy. The factors driving the performance and cost of the two generic wind projects are provided in Table 9.

Table 9

Factor	Options	Comments
Turbine Options	Vestas 116-2.0	The generic wind projects developed for this study use a 2 MW utility scale turbine manufactured by Vestas. This turbine is available with several different blade configurations suitable to different wind regimes and is representative of the cost and performance that can be expected from a range of turbine equipment available from multiple manufacturers. In addition, APUC has recent experience in the development and operations of projects using this turbine. No decision on turbine manufacturer have been made at this time.
Annual Capacity Factor	Mid LCOE Wind Low LCOE Wind	Empire developed two generic wind projects that are representative of a range of projects that could reasonably be developed to serve Empire's customers. The annual capacity factor, or annual energy production used for these sites was based on studies performed by Empire using long-term meteorological data, manufacturer's performance data, and industry standard assumptions regarding facility performance. In addition Empire used actual operations data from the Elk River Wind project to validate and calibrate these models. Project 1: sited inside Empire's service territory near the existing Asbury coal facility identified as the Mid LCOE Wind project. Project 2: represents a range of potential projects located in higher wind areas located to the west of the Empire service territory. Energy forecasts and basis assumptions were based on the

		performance of the Elk River wind farm located in Kansas and under contract with Empire.
Commercial Operation Date	2020 or earlier 100% PTC 2021 80% PTC 2022 60% PTC 2023 40% PTC 2024 or later no PTC value	A key aspect of the overall economic value of the studied wind projects is the impact of project development timing on the value of PTCs. Empire intends to employ a strategy of using safe harbor turbine components to maximize the value of these tax incentives; however the value of these tax incentives declines over time, thus Empire has developed separate cases reflecting the impact of project timing.
Interconnection/ Transmission Cost	Low (Mid LCOE Wind) High (Low LCOE Wind)	As part of the overall capital costs for the studied wind projects Empire has included the cost of interconnecting the proposed wind projects. This includes costs to physically interconnect the projects, which has been based on Empire and APUC's experience with other similar projects. In addition, Empire has developed assumptions of additional transmission system network upgrades that would be required for new projects. Empire has assumed lower costs for projects located within its service territory and higher costs for projects located further from its service territory.
Electrical Basis		Market prices for Mid LCOE wind were assumed to be equivalent to Asbury prices developed to model the SPP IM. Market prices for Low LCOE wind were assumed to be equivalent to Elk River prices.
Capital Cost		Capital costs for the different studied cases were based on recent experience from APUC's project development work and recent equipment quotations from major equipment suppliers. In addition, the capital cost of wind turbine equipment is expected to decline in real terms over the study horizon. The integrated modeling performed by ABB looks only at the net capital cost to Empire customers after considering capital contributions from Tax Equity Investors.
Operating Cost		Fixed operating costs for the studied projects assumes that Empire enters into long term Operation and Maintenance agreements with the wind turbine equipment vendors. In addition, fixed operating costs include balance of plant operating expenses based on APUC's operating experience and in line with the National Renewable Energy Laboratory (NREL)'s forecast. Finally, the variable operating and maintenance costs include payments that would be required under the tax equity financing structure.

Based on these factors, Empire developed a range of costs for the different generic wind projects under different commercial operation dates. These different cases are presented in Table 10 and Table 11.

Table 10

The Empire District Electric Company ("EDE") - Low LCOE Wind Analysis

Production Tax Credit ("PTC") Scenarios						
Commercial Operation Date			**2019**	**2022**	**2023**	**2024**
% of PTC			*100%*	*60%*	*40%*	*0%*
Capacity (MW)			100.5	100.5	100.5	100.5
Turbine			Vestas V116 2.0 MW	Vestas V116 2.0 MW	Vestas V116 2.0 MW	Vestas V116 2.0 MW
Number of Turbines			49	49	49	49
Net Capacity Factor			54.1%	54.1%	54.1%	54.1%
Capital Costs		**2016 Real ($000s)**	**Nominal ($000s)**			
Wind Turbines		$ 95,269	$ 97,174	$ 97,174	$ 97,174	$ 97,174
Balance of Plant	**Note A**	$ 60,652	$ 64,364	$ 68,303	$ 69,670	$ 71,063
Electrical Interconnect		$ 260	$ 275	$ 292	$ 298	$ 304
Total Facility Cost		$ 156,180	$ 161,813	$ 165,770	$ 167,142	$ 168,541
Development Costs		$ 8,436	$ 8,952	$ 9,500	$ 9,690	$ 9,884
Tax Equity / Lender Legal		$ 1,745	$ 1,852	$ 1,966	$ 2,005	$ 2,045
Legal		$ 782	$ 829	$ 880	$ 898	$ 916
Upfront Fees		$ 2,137	$ 2,192	$ 2,225	$ 2,237	$ 2,249
IDC and Commitment Fees		$ 1,414	$ 1,452	$ 1,473	$ 1,481	$ 1,488
Total Capital Costs		$ 170,694	$ 177,090	$ 181,814	$ 183,452	$ 185,123
Total Cost per MW		$ 1,698	$ 1,762	$ 1,809	$ 1,825	$ 1,842
PAYGO						

Tax Equity Assumptions ($000's)						
Commercial Operation Date			**2020**	**2022**	**2023**	**2024**
% of PTC			*100%*	*60%*	*40%*	*0%*
Total Project Costs			$ 177,091	$ 181,814	$ 183,452	
Tax Equity Contribution			$ 105,500	$ 72,000	$ 56,700	
PAYGO			$ 27,846	$ 16,707	$ 10,594	
Capital Contribution from EDE			$ 71,591	$ 109,814	$ 126,752	
Capital Contribution from EDE ($/MW) [Nominal]	**Note B**		$ 712	$ 1,093	$ 1,261	
Capital Contribution from EDE ($/MW) [2016 Real]	**Note B**		$ 671	$ 970	$ 1,098	
Cash Allocation Y1-Y5 - Tax Equity			0%	0%	0%	
Cash Allocation Y1-Y5 - Sponsor			100%	100%	100%	
Cash Allocation Y6-Y10 - Tax Equity			60%	45%	55%	
Cash Allocation Y6-Y10 - Sponsor			40%	55%	45%	
Cash Allocation Post Flip - Tax Equity			11%	10%	5%	
Cash Allocation Post Flip - Sponsor			89%	90%	95%	
Tax Allocation Y1-Y5 - Tax Equity			99%	99%	90%	
Tax Allocation Y1-Y5 - Sponsor			1%	1%	10%	
Tax Allocation Y6-Y10 - Tax Equity			99%	99%	99%	
Tax Allocation Y6-Y10 - Sponsor			1%	1%	1%	
Tax Allocation Post Flip - Tax Equity			11%	10%	5%	
Tax Allocation Post Flip - Sponsor			89%	90%	95%	

Operation & Maintenance ("O&M") Costs						
			2016 Real ($000s)			
Commercial Operation Date			**2020**	**2022**	**2023**	**2024**
% of PTC			*100%*	*60%*	*40%*	*0%*
Variable O&M						
Levelized Variable O&M ($/MWh) Y1-10	**Note C**		$ (2.98)	$ (0.34)	$ 2.68	
Levelized Variable O&M ($/MWh) Y11-30	**Note C**		$ 1.46	$ 1.83	$ 1.56	
Fixed O&M						
Levelized Fixed O&M ($/kW-yr)	**Note D**		$ 46.88	$ 49.14	$ 50.98	

NOTES

A Balance of Plant costs are comprised of the following material items: 1) Collection System & Transformer; 2) Civil & Roads; 3) Turbine Foundations; 4) Erection Labour & Commissioning; 5) Mobilization

B Figures are shown in nominal dollars (assuming a 2.0% inflation rate)

C Variable O&M cost is reflective of the cash allocation to the tax equity investor

D Fixed O&M costs are comprised of the following material items: 1) Turbine O&M; 2) Non-Turbine O&M (including BOP labour, preventative maintenance and asset management costs); 3) Insurance; 4) Land Lease Payments; 5) Property Tax

Table 11

The Empire District Electric Company ("EDE") - Mid LCOE Wind Analysis

Production Tax Credit ("PTC") Scenarios							
Commercial Operation Date			**2020**	**2021**	**2022**	**2023**	**2024**
% of PTC			*100%*	*80%*	*60%*	*40%*	*0%*
Capacity (MW)			100.5	100.5	100.5	100.5	100.5
Turbine			Vestas V116 2.0 MW	Vestas V116 2.0 MW	Vestas V116 2.0 MW	Vestas V116 2.0 MW	Vestas V116 2.0 MW
Number of Turbines			49	49	49	49	49
Net Capacity Factor			46.4%	46.4%	46.4%	46.4%	46.4%
Capital Costs		**2016 Real ($000s)**	**Nominal ($000s)**				
Wind Turbines		$ 95,269	$ 97,174	$ 97,174	$ 97,174	$ 97,174	$ 97,174
Balance of Plant	**Note A**	$ 60,652	$ 65,651	$ 66,964	$ 68,303	$ 69,670	$ 71,063
Electrical Interconnect		$ 260	$ 281	$ 287	$ 292	$ 298	$ 304
Total Facility Cost		$ 156,180	$ 163,106	$ 164,425	$ 165,770	$ 167,142	$ 168,541
Development Costs		$ 8,436	$ 9,131	$ 9,314	$ 9,500	$ 9,690	$ 9,884
Tax Equity / Lender Legal		$ 1,745	$ 1,889	$ 1,927	$ 1,966	$ 2,005	$ 2,045
Legal		$ 782	$ 846	$ 863	$ 880	$ 898	$ 916
Upfront Fees		$ 2,137	$ 2,203	$ 2,214	$ 2,225	$ 2,237	$ 2,249
IDC and Commitment Fees		$ 1,414	$ 1,459	$ 1,466	$ 1,473	$ 1,481	$ 1,488
Total Capital Costs		$ 170,694	$ 178,634	$ 180,208	$ 181,814	$ 183,452	$ 185,123
Total Cost per MW		$ 1,698	$ 1,777	$ 1,793	$ 1,809	$ 1,825	$ 1,842
PAYGO							

Tax Equity Assumptions ($000's)						
Commercial Operation Date		**2020**	**2021**	**2022**	**2023**	**2024**
% of PTC		*100%*	*80%*	*60%*	*40%*	*0%*
Total Project Costs		$ 178,634	$ 180,208	$ 181,814	$ 183,452	
Tax Equity Contribution		$ 95,000	$ 76,000	$ 67,500	$ 56,900	
PAYGO		$ 23,895	$ 19,116	$ 14,025	$ 8,935	
Capital Contribution from EDE		$ 83,634	$ 104,208	$ 114,314	$ 126,552	
Capital Contribution from EDE ($/MW) [Nominal]	**Note B**	$ 832	$ 1,037	$ 1,137	$ 1,259	
Capital Contribution from EDE ($/MW) [2016 Real]	**Note B**	$ 769	$ 939	$ 1,010	$ 1,096	
Cash Allocation Y1-Y5 - Tax Equity		0%	0%	0%	0%	
Cash Allocation Y1-Y5 - Sponsor		100%	100%	100%	100%	
Cash Allocation Y6-Y10 - Tax Equity		56%	35%	57%	68%	
Cash Allocation Y6-Y10 - Sponsor		44%	65%	44%	32%	
Cash Allocation Post Flip - Tax Equity		11%	12%	5%	5%	
Cash Allocation Post Flip - Sponsor		89%	88%	95%	0%	
Tax Allocation Y1-Y5 - Tax Equity		99%	99%	95%	87%	
Tax Allocation Y1-Y5 - Sponsor		1%	1%	5%	13%	
Tax Allocation Y6-Y10 - Tax Equity		99%	99%	99%	99%	
Tax Allocation Y6-Y10 - Sponsor		1%	1%	1%	1%	
Tax Allocation Post Flip - Tax Equity		11%	12%	5%	5%	
Tax Allocation Post Flip - Sponsor		89%	88%	95%	95%	

Operation & Maintenance ("O&M") Costs						
				2016 Real ($000s)		
Commercial Operation Date		**2020**	**2021**	**2022**	**2023**	**2024**
% of PTC		*100%*	*80%*	*60%*	*40%*	*0%*
Variable O&M						
Levelized Variable O&M ($/MWh) Y1-10	**Note C**	$ (2.20)	$ (1.84)	$ 1.26	$ 5.06	
Levelized Variable O&M ($/MWh) Y11-30	**Note C**	$ 1.94	$ 2.31	$ 1.32	$ 2.06	
Fixed O&M						
Levelized Fixed O&M ($/kW-yr)	**Note D**	$ 47.59	$ 48.46	$ 49.31	$ 51.22	

NOTES

A Balance of Plant costs are comprised of the following material items: 1) Collection System & Transformer; 2) Civil & Roads; 3) Turbine Foundations; 4) Erection Labour & Commissioning; 5) Mobilization

B Figures are shown in nominal dollars (assuming a 2.0% inflation rate)

C Variable O&M cost is reflective of the cash allocation to the tax equity investor

D Fixed O&M costs are comprised of the following material items: 1) Turbine O&M; 2) Non-Turbine O&M (including BOP labour, preventative maintenance and asset management costs); 3) Insurance; 4) Land Lease Payments; 5) Property Tax

NOTES

A Balance of Plant costs are comprised of the following material items: 1) Collection System & Transformer; 2) Civil & Roads; 3) Turbine Foundations; 4) Erection Labour & Commissioning; 5) Mobilization

B Figures are shown in nominal dollars (assuming a 2.0% inflation rate)

C Variable O&M cost is reflective of the cash allocation to the tax equity investor

D Fixed O&M costs are comprised of the following material items: 1) Turbine O&M; 2) Non-Turbine O&M (including BOP labour, preventative maintenance and asset management costs); 3) Insurance; 4) Land Lease Payments; 5) Property Tax

Tax Equity Financing

A key driver to the cost savings from wind additions is the use of tax equity financing to unlock the value of various tax incentives provided by the federal government for the construction and operation of new wind projects.

There are two primary tax incentives provided by the federal government for new wind projects. First, new wind projects are provided accelerated tax depreciation using the 5 year Modified Accelerated Capital Recovery System ("MACRS") depreciation schedule. Second, for the first 10 years of operations qualifying wind projects generate one PTC for every MWh of electrical energy generated and delivered to the grid. The value of each PTC is $24, which escalates with the US Consumer Price Index. In 2015, Congress approved an extension of these tax credit programs for wind projects. This extension defines a phase down in the value of the PTCs, as summarized in Table 12:

Table 12

Construction Start Date	PTC Value (2017$)	4-year Construction Period	PTC Period
Dec 31, 2016	100% $24.00/MWh	2017 – 2020	2021 – 2030
Dec 31, 2017	80% = $19.20/MWh	2018 – 2021	2022 – 2031
Dec 31, 2018	60% = $14.40/MWh	2019 – 2022	2023 - 2032
Dec 31, 2019	40% = $9.60/MWh	2018 - 2023	2024 - 2033

Construction Start Date: The date on or before which projects must commence construction to qualify for the different PTC levels. The IRS has provided guidance clarifying activities required to meet the definition of commencement of construction for the purposes of determining eligibility for the PTC. One of the qualifying activities for the commencement of construction is the purchase of equipment components representing 5 percent or more of the overall capital cost of the proposed project. Empire intends to work with project developers which have already procured safe harbor components to maximize the value of the PTCs for the studied projects.

PTC Value: The table above presents 2017 values for these credits, which are escalated with the US Consumer Price Index on an annual basis.

4-Year Construction Period: Once construction has commenced on a particular project, construction must be completed, with the project achieving commercial operation, within four (4) years. For example, if construction for a project begins prior to December 31, 2016, the construction must be complete and achieve commercial operation by December 31, 2020 to qualify for the full PTC value.

PTC Period: Following commencement of operation, projects generate PTCs for a period of ten years. In Empire's case, the most viable way to maximize the benefits of the PTCs is to work with a tax equity financing partner. Tax equity financing will be utilized as a means of unlocking the full value of the renewable energy projects and maximizing these benefits for Empire customers. The value is unlocked with a tax equity partner by receiving the full benefit of the PTC at the beginning of the project rather than realizing the benefits in future years delaying the impact of the savings.

Tax equity financing is a common method of financing the development of new renewable energy projects, which Algonquin has itself used before. While identifying existing wind projects available for purchase, Empire will work with various tax equity providers to optimize the project structure to maximize the value of renewable energy projects for Empire's customers.

In a tax equity financed renewable energy project, the tax equity partner makes an initial investment in the project - typically 40% – 60% of the capital cost of the project - and may make subsequent smaller capital investments over the project life. This tax equity structure is known as Pay-as-you-go or PAYGO[7]. For the 100% PTC Mid LCOE wind projects the Generation Fleet Savings Analysis model assumed 53% tax equity funding up front with another 14% coming in years 1-10 through PAYGO contributions. For the 100% PTC Low LCOE wind projects the Analysis assumed 60% tax equity funding up front with another 15% coming in years 1-10 through PAYGO contributions[8]. In return for this investment, the tax equity partner will obtain a partnership interest in the wind project. This partnership interest will provide the tax equity partner; (i) 99% of the PTCs, (ii) some amount of the accelerated depreciation benefits; and (iii) partnership distributions. For the structure contemplated in this analysis, the tax equity partner will receive a payment between \$3 and \$6/MWh (in 2016 dollars) when levelized over the 30 year life of the project.

Key assumptions used in ABB's tax equity financing modeling include the following:

- Capital costs for wind projects are net of tax equity financing in rate based calculations.
- Overall financing structures used based on similar projects recently financed by Algonquin and Liberty Utilities
- Total tax equity contribution adjusted to reflect the modeled project performance, in terms of total PTCs generated.

Liberty Utilities Experience with Tax Equity Financing

Liberty Utilities has successfully utilized tax equity financing to support the development of the 50 MW Luning Solar project to provide renewable energy for the customers of Liberty CalPeco serving 50,000 customers in Lake Tahoe, California. The Luning project was completed in early 2017 and is currently providing low cost renewable energy for Liberty Utilities' California customers. An additional 10 MW is being added to Luning, referred to as the Turquoise Project, for a total of 60 MW. Empire has relied on Liberty Utilities' experience with the Luning Project and Algonquin's experience in financing several wind projects, including the Odell 200 MW wind project, the Great Bay 75 MW solar project, and the Deerfield 149 MW wind project.

As a result of this financing structure, Empire expects that approximately 40% of the total capital cost of the studied wind projects will be included in rate base, with the remainder

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[7] Pay-as-you-go (PAYGO) tax equity structure enables the tax equity investor to pay an upfront amount, with continuing payments being made to the sponsor over a period of time. The PAYGO payments are a percentage of the production tax credits the tax equity investor receives.

[8] See Table 10 and 11.

financed by the tax equity partner. However, as the PTCs are phased out the potential contribution from tax equity financing will decline. Table 10 and Table 11 provide details of the financing structure.

Fast Start Internal Combustion Engines

The following updates to the price of Reciprocating Engines were made during the GFSA all in 2016 dollars:

Table 13

	2016 IRP	Generation Fleet Savings Analysis
Full Load Heat Rate (btu/kWh)	8,350	8,227
Capital Costs ($/kW)	1,248	1,072
Fixed O&M ($/kW-yr)	9.64	11.43
Variable O&M ($/MWh)	3.05	3.2

The updated pricing and performance was provided by Wartsila. The model did not account for any ancillary service revenue that may be associated with the fast start performance of the reciprocating engines.

Utility Scale Solar

The following updates to the cost and performance of utility scale solar were completed:

- Single access tracker ground mount PV projects
- 23% capacity factor – increased due to technology improvements and tracker performance
- 1.25% accredited capacity per MW of name plate size. This is a conservative estimate based on Empire's peak load and a typical solar generation profile
- $1.2/W DC for installed costs. Note: this pricing was established before the current trade dispute on solar panel and pricing could change depending on the result of those hearings.
- Utilization of tax equity to monetize the 30% Investment Tax Credit (ITC) which will step down to 10% from 2019 to the end of 2022. It is expected that the technology costs will drop faster than the reduction in the ITC so the pricing assumptions are valid for the entire 20 year supply-side planning horizon.
- $24/kW-yr for operational costs.
- $4.5/MWh in assumed payments to tax equity

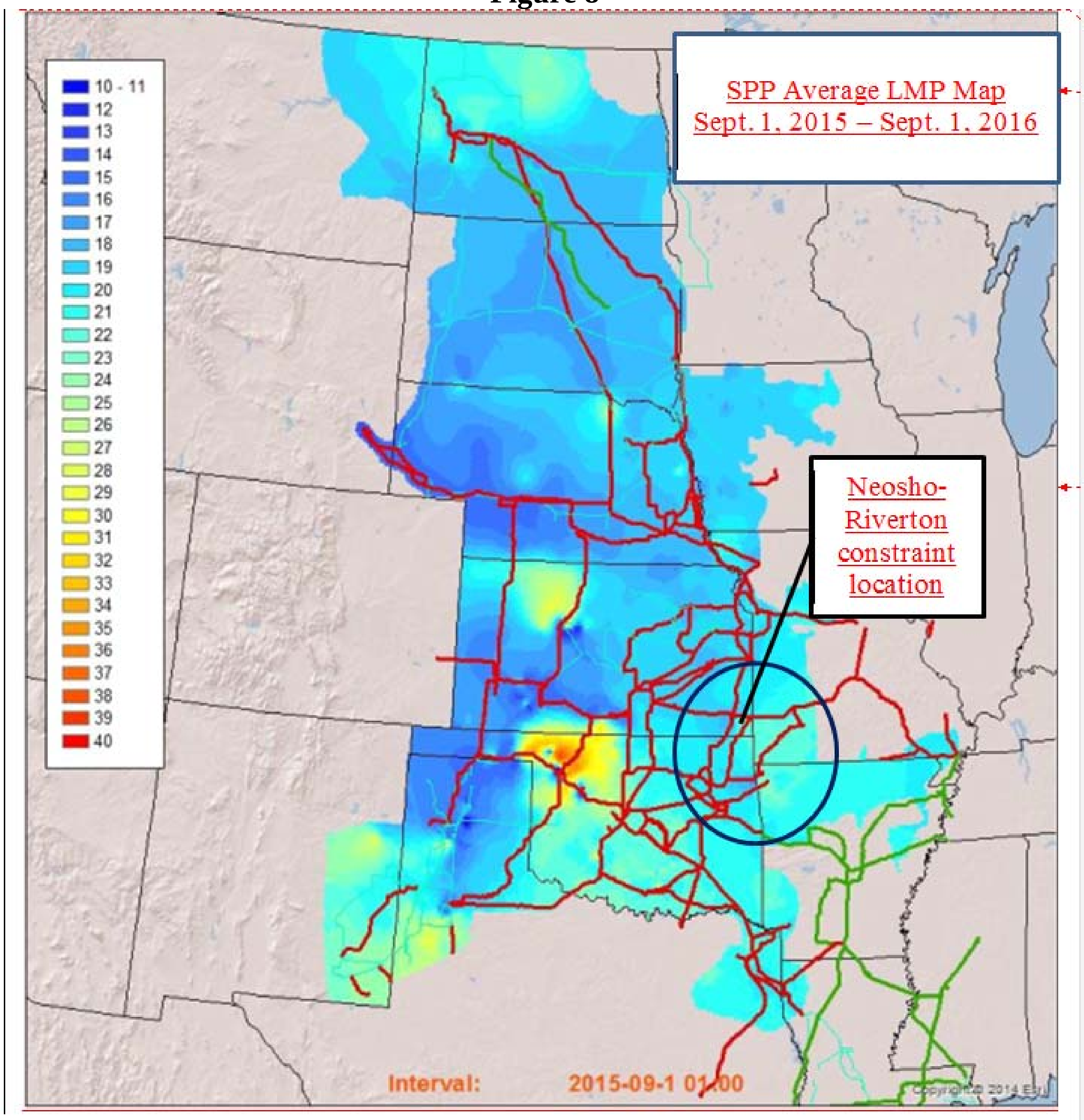
The updated pricing and performance were provided by Liberty based on current solar project cost projections as well as a review of current market offers for solar facilities.

Transmission Assumptions

The Generation Fleet Savings Analysis did not assume transformational transmission changes that would impact the Empire service area. Neosho – Riverton 161 kV and Neosho

– Blackberry 345 kV are two of the parallel west to east flow paths on the southern border of Kansas and Missouri. For the loss of the 345 kV, the 161 kV line becomes a binding constraint. Generation to the west side of the constraint serves load on the east side, including the Empire customer's load. This constraint has been studied as part of the SPP – MISO seams projects within the SPP transmission projects and has not been selected for upgrade. As such, Empire did not assume any immediate change to the transmission layout and addressed the uncertainty through basis assumptions in the critical uncertain factors.

Figure 8



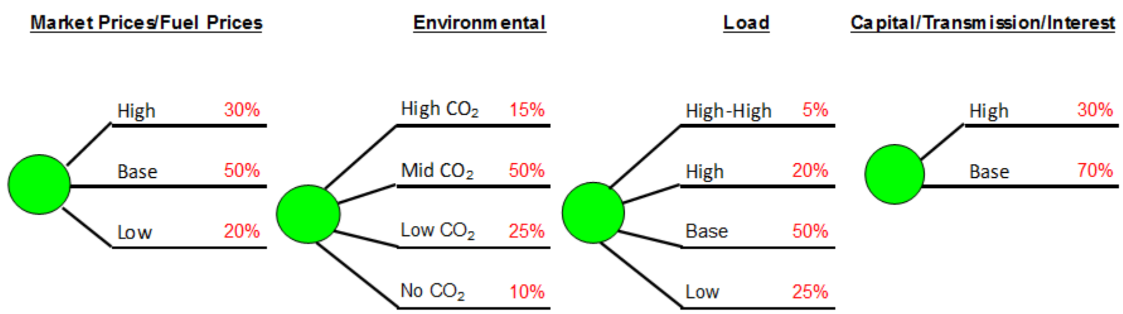
New projects located on the east side of the Neosho – Riverton constraint were assumed to have low interconnection costs from a system impact perspective, as well as the network service perspective. New projects on the west side of the Neosho – Riverton constraint were assumed to have higher interconnection costs for system impact and network service perspective. Empire did not assume that new projects would materially change the transmission constraints in the area as wind projects to the west of the constraint are likely to be developed with or without Empire. Projects to the east will help ease the benefit but are not large enough to alleviate the constraint.

The 2016 IRP utilized approximately $61 per kW of interconnection costs related to network upgrades for new generation based on an analysis of avoided costs. For the analysis, the Mid LCOE wind interconnection costs were assumed to be half of the base assumption of $61 per kW as it was assumed the interconnection would occur at or near the Empire service territory and therefore not require significant upgrades to deliver the capacity to the Empire customers. Alternatively, new Low LCOE wind sites were assumed to require double the base assumption of $61 per kW, due to rapidly increasing wind generation in Kansas, all of which has not yet been included in SPP Integrated Transmission Planning (ITP) studies.

5. Critical Uncertain Factors

In the 2016 IRP, Empire identified the following critical uncertain factors: environmental; market prices/fuel prices; load; and capital/transmission/interest rates.

Figure 9



These factors were re-examined in the context of the Generation Fleet Savings Analysis and evaluated to determine if any changes in the market since the 2016 IRP warranted changes in the critical uncertain factors. In addition to the categories listed as critical, the probability of each scenario was also reviewed.

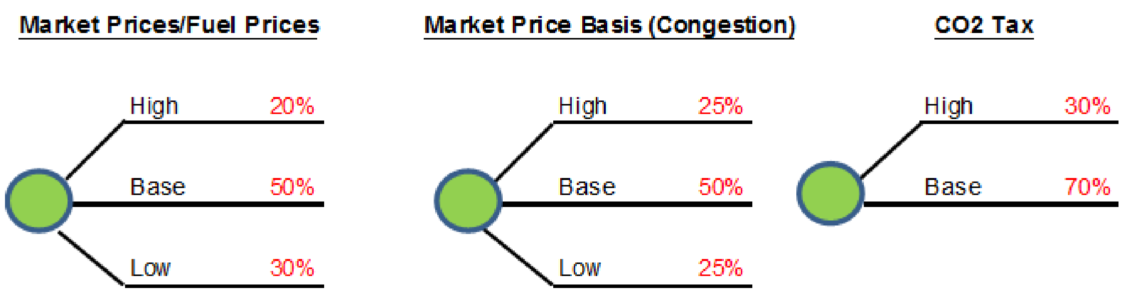
Empire recently completed its Environmental Compliance Plan which brought all generating units into compliance with current and expected environmental legislation with the exception of Asbury. The costs to install a landfill and implement the bottom ash conversion to comply with coal combustion residuals and the CWA Steam Electric Effluent Guidelines were considered as part of the assumptions related to Asbury for each of the seven scenarios studied. The timing of any CO2 tax was determined to be delayed, but still a possibility in the future. In the 2016 IRP it was assumed carbon pricing would go into effect in 2022. For the purposes of this Generation Fleet Savings Analysis, no carbon pricing was assumed for the base scenarios. CO2 was included as a critical uncertain factor in the Generation Fleet Savings Analysis. The carbon scenarios uses a start date of 2030, with the base being $0 carbon and high being the ABB carbon forecast.

Given that all Empire load is purchased from the SPP IM and all generation is sold to the SPP IM, it was determined that load is not an uncertain factor for purposes of the analysis.

Transmission risk factors were addressed as mentioned in the previous section. While it is still a risk, the costs associated with variations in deliverability were accounted for in the market basis. This is primarily due to selling generation into the market at the point of interconnection rather than delivering to Empire's load area. The costs associated with interconnection were accounted for in the seven scenarios which modeled wind at different capacity levels for both Mid and Low LCOE wind sites.

As a result, the critical uncertain factors have been updated to the following:

Figure 10



(Source: ABB Advisors.)

6. Risk Analysis

In this section, Empire describes and documents the process and rationale used by its decision makers to assess tradeoffs between different resource options and to determine the appropriate balance between minimization of expected costs and other considerations, such as critical uncertain factors, in selecting the preferred resource plan and developing the resource acquisition strategy.

Decision Makers
Table 14 shows the list of the utility decision makers for the purposes of this Generation Fleet Savings Analysis and the IRP process.

Table 14

Name	Title
David Swain	President
Blake Mertens	Vice-President – Operations-Electric
Peter Eichler	Vice President – Centralized Operations
Rob Sager	Vice-President – Finance and Administration
David Pasieka	Chief Operating Officer – Liberty Utilities

Empire further notes that any significant capital project, such as the development of the wind generation proposed here, would require approval from Empire's Board of Directors.

Risk Profiles

ABB utilized the Strategic Planning Risk Module to develop cumulative probability distributions which are also known as Risk Profiles.

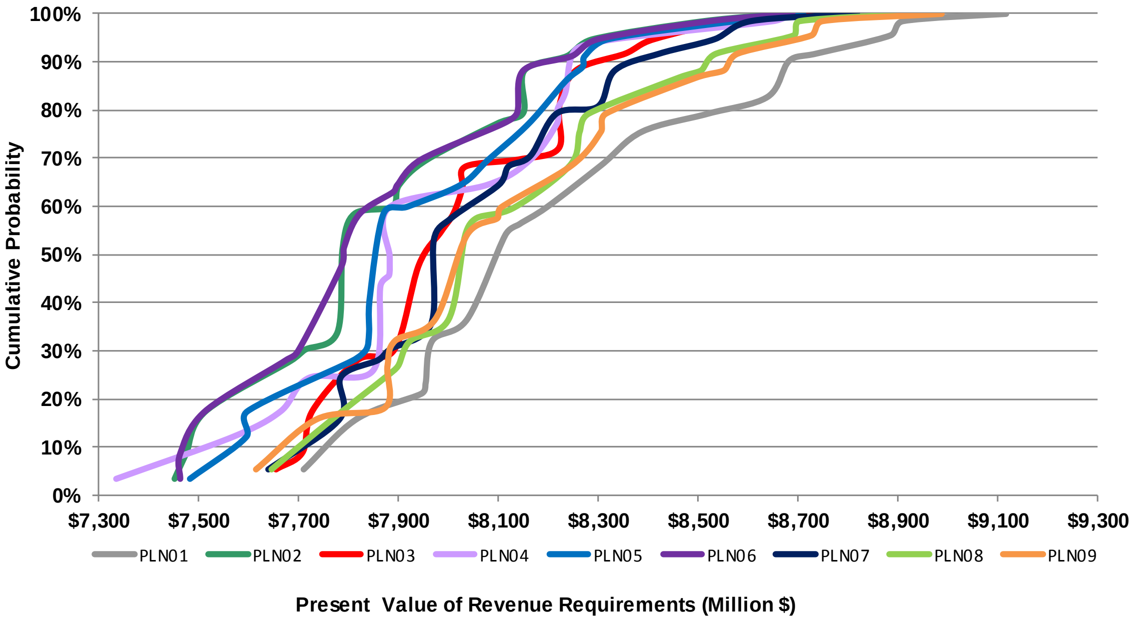
Risk Profiles provide the ability to visually assess the risks associated with a decision under uncertainty. For this analysis, ABB and Empire used decision analysis techniques to create a decision tree around the three critical uncertain factors, described in the section above.

- Market Prices/Fuel Prices: Market Prices were developed for SPP-KSMO with the use of the various gas price forecasts developed by PROMOD IV and published in the 2016 Fall Reference Case;
- Carbon Tax: ABB's Carbon Tax Scenario was modeled starting in 2030; and
- Market Price Basis: ABB applied a monthly spread to the zonal price to create nodal prices. The monthly spread was based on 2016 historical average differences between the actual zonal and nodal points of interest to the prices, subject to a standard deviation calculation to check for outliers. The high basis adder was 200% higher than base and the low basis adder was 25% of base.

The following decision tree represents the critical uncertain factors considered for each plan. There are a total of 18 combinations also known as endpoints as shown in **Figure 10.**

The risk profile can be used to determine the probability that PVRR will be a particular value. Using the Base 800 Wind plan (PL NO2) as an example in the figure below, there is a 10% probability that PVRR could be as much as $8.2 billion with an expected value of $7.9 billion. From the prior deterministic simulation, the PVRR value was $7.8 billion under "base case" conditions. The $86.6 million difference between the expected value and the deterministic value is "real option value" or extrinsic value. This reflects the risk of the Plan with future uncertainty. The real option value for each plan is shown in **Figure 12**. The extrinsic value is shaded.

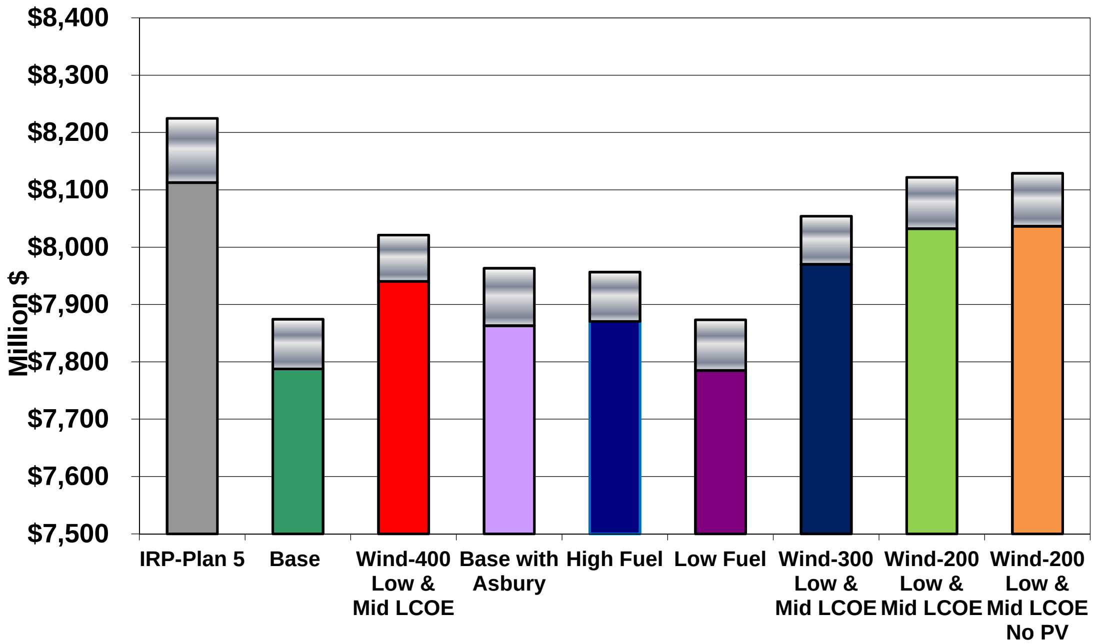
Figure 11
All Base Scenarios – Risk Profiles (2018 – 2037)



(Source: ABB Advisors.)

Figure 12

PVRR with Risk Value (2018-2037) Deterministic + Stochastic



(Source: ABB Advisors.)

The risk weighted PVRR results show that Plan 2 and Plan 6 continue to offer the lowest cost to customers. Furthermore, with more assets without fuel costs, the total probable risk is reduced for customers. This can be seen further when comparing Plan 2 to Plan 4 using the risk weighted values. Plan 2 is now $89 million dollars less over 20 years, which is $14 million dollars of additional savings when compared to the deterministic values. What does this mean? Shutting down Asbury reduces risk by $14 million dollars over the next 20 years.

Table 15
Risk Weighted PVRR

	Plans – ($ millions)	Deterministic	Risk	Risk Weighted Cost
Plan 1	IRP-Plan 5	8,113	112	8,225
Plan 2	Base	7,788	87	7,874
Plan 3	Wind-400 Low & Mid LCOE	7,941	81	8,021
Plan 4	Base with Asbury	7,863	100	7,963
Plan 5	High Fuel	7,871	86	7,957
Plan 6	Low Fuel	7,785	88	7,873
Plan 7	Wind-300 Low & Mid LCOE	7,970	84	8,054
Plan 8	Wind-200 Low & Mid LCOE	8,032	89	8,122
Plan 9	Wind-200 Low & Mid LCOE No PV	8,037	92	8,129

7. Results

Through the use of the ABB modelling software with the updated inputs and assumptions, Empire was able to ascertain that the least cost plan using the measure of net present value revenue requirements (PVRR) was the Low Fuel Plan over 20 years (Plan 6) and the Base Plan over 30 years (Plan 2). Table 16 shows the results from all of the plans. Plan 1 (IRP-Preferred Plan), was the 2016 triennial selected plan.

Table 16

Plan	Description	20 Year PVRR	20 Year Rank	30 Year PVRR	30 Year Rank
Plan 1	IRP-Plan 5	$8,113	9	$10,410	9
Plan 2	**Base**	**$7,788**	**2**	**$9,803**	**1**
Plan 3	**Wind-400 Low & Mid LCOE**	**$7,941**	**5**	**$9,989**	**4**
Plan 4	Base with Asbury	$7,863	3	$10,001	5
Plan 5	High Fuel	$7,871	4	$9,874	3
Plan 6	Low Fuel	$7,785	1	$9,809	2
Plan 7	Wind-300 Low & Mid LCOE	$7,970	6	$10,061	6
Plan 8	Wind-200 Low & Mid LCOE	$8,032	7	$10,195	7
Plan 9	Wind-200 Low & Mid LCOE No PV	$8,037	8	$10,219	8

By design, the plans have different amounts of Low and Mid LCOE wind additions, so when performing comparisons, it is necessary to look at plans that have the same wind capacity and wind costs. Plans 2, 4, 5, and 6 all contain 800 MW of Low LCOE wind in 2019, so are directly comparable. Plan 3, on the other hand, procures 50% of the 800 MW of wind from Mid LCOE wind, reducing the savings calculated in Plan 2 by $153 million over 20 years and $186 million over 30 years.[9] Given this wind constraint, Plan 3 is not directly comparable to Plan 4, without making an adjustment for the higher cost of wind. Plans 7, 8 and 9 also assume that 50% of the wind is procured at Mid LCOE pricing, but add only 600 MW (Plan 7) or 400 MW (Plans 8 and 9) of total wind. Therefore, these plans are useful to compare with Plan 3, in order to measure the impact of varying amounts of wind additions.

Figure 13 and Figure 14 summarize the PVRR results for 30-year and 20-year terms, respectively, and the following commentary explains the key findings in more detail:

- **<u>Least Cost Plans</u>:** Plan 6, Low Fuel actually shows the lowest PVRR over 20 years, although its costs are very close to Plan 2's costs. The only difference between Plan 6, Low Fuel and Plan 2, Base 800 Wind, is a 100 MW solar facility in 2031. The 100 MW solar facility does not have a material impact on the results in either direction at this time. Since the solar facility is still far into the future and can be assessed again, Plan 2 and Plan 3 were deemed the most reasonable plans to form the high and low range of savings in the customer savings plan.

[9] Plan 3 constrains the model to building a maximum of 400 MW of Low LCOE wind, with the rest met by Mid LCOE wind, up to an 800 MW limit. Other than this Low LCOE wind constraint, Plan 2 and Plan 3 have the same optimized portfolios. Thus, the differences of $153 million (20 year PVRR) and $186 million (30 year PVRR), reflect the cost of moving to the blended wind portfolio.

- **Range of Savings for Low and Mid LCOE Plans:** Plan 2, Base 800 Wind and Plan 3, Wind - 400 Low & Mid LCOE show the expected range of customer savings that can be achieved by adding 800 MW of new wind and retiring Asbury. In fact, the more wind added in each plan, the lower the PVRR becomes, as can be seen in Plans 7, 8, 9 and 1. Plan 2 and Plan 3 become the high and low range of the Customer Savings Plan with the two primary tenants of utilizing 800 MW of new wind and retiring Asbury to save customers money and reduce risk, while maintaining reliable service. The final cost and benefit of the Customer Savings Plan will be known after the request for proposals is complete.

- **Impact of Retiring Asbury:** To look at the impact of retiring Asbury, Plan 4 should be compared to Plan 2, Base. This shows that there is a significant benefit in retiring Asbury early: $75 million over 20 years and $198 million over 30 years. As discussed above, Plan 4 should not be compared to Plan 3 without increasing the costs in Plan 4 by $153 million in the 20 year scenario.

- **Impact of Adding Solar**: When looking at the impact of solar, Plan 2 can be compared with Plan 6 or Plan 8 can be compared with Plan 9. The wind and Asbury assumptions are the same in those plans, so the primary difference is the solar additions. In Plan 2, 100 MW of solar is built in 2031, whereas in Plan 6, no solar is built. In Plan 8, 50 MW of solar is built in 2025, 100 MW in 2026 and 50 MW 2031, whereas in Plan 9, no solar is built. The results show that solar has a slight negative over 20 years (~$3 million) and a slight benefit over 30 years, ranging from $6 to $24 million, depending on which plans are compared.

Figure 13

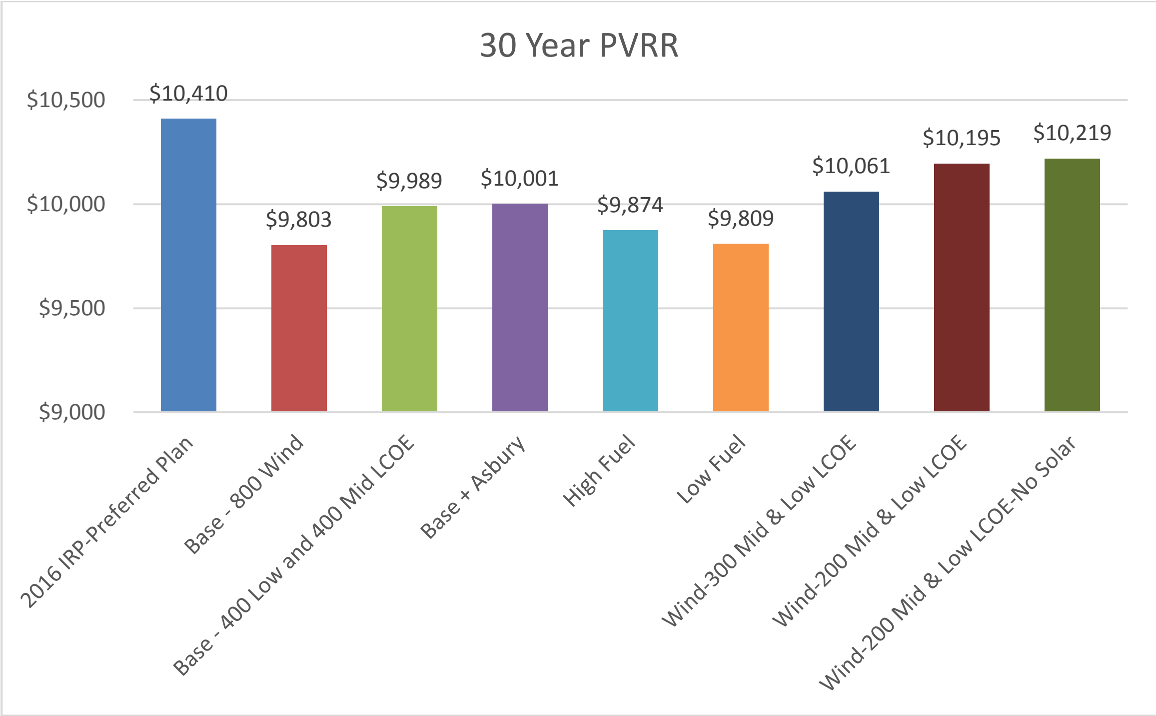
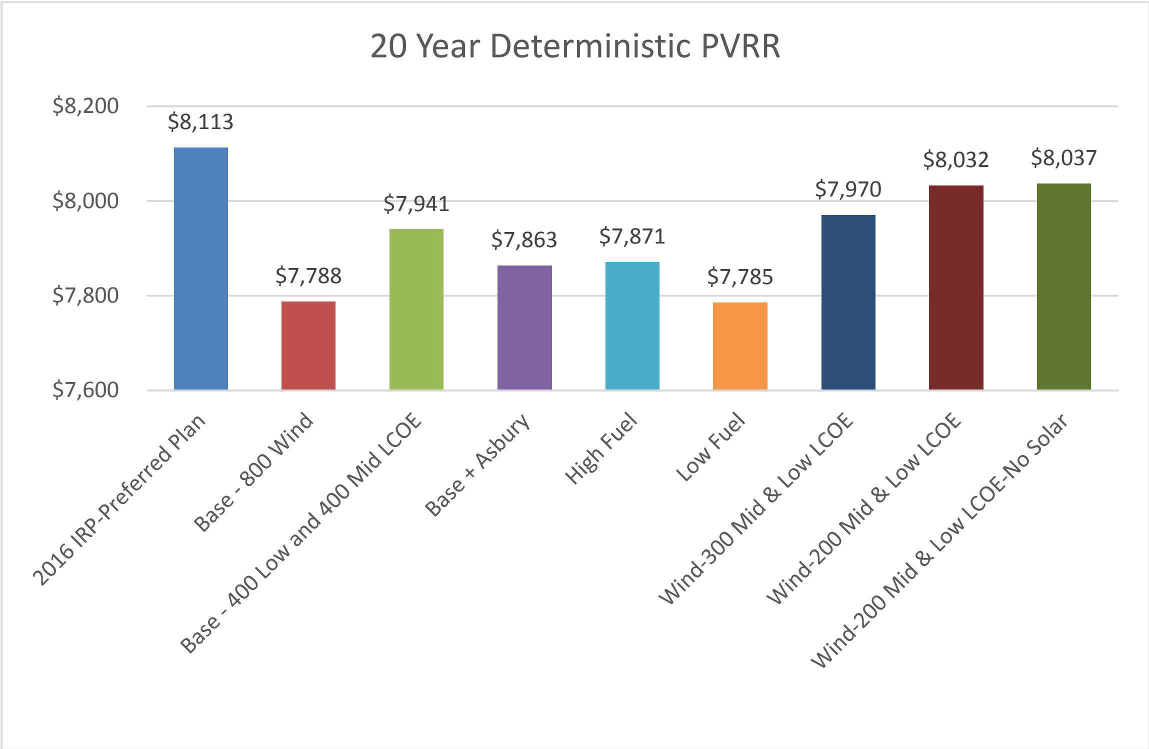


Figure 14



Drivers of the Reduction in PVRR

This section looks at the differences in Plan 1, 2016 IRP Preferred Plan and the Customer Savings Plan, adding 800 MW of wind and retiring Asbury as represented by the range of savings shown in Plan 2, Base and Plan 3, Wind - 400 Low & Mid LCOE. The primary differences in the three plans are listed below:

Table 15

2016 IRP Preferred Plan	Customer Savings Plan – High savings range	Customer Savings Plan – Low savings range
• Current assets – no additional generation assets until 2029	• Retire Asbury in 2019 • Add 800MW of Low LCOE wind in 2019 - 2020.	• Retire Asbury in 2019 • Add 400MW of Low LCOE wind in 2019 - 2020. • Add 400 MW of Mid LCOE wind by 2020.

The cost additions and savings of each of the three changes are addressed below:

800 MW of Low LCOE Wind

The addition of 800 MW of Low LCOE wind projects in the customer savings plan – high savings range are expected to generate a present benefit of $1,434 million over the next 20 years and $1,949 million over the next 30 years. Benefit is defined as SPP market revenue minus fuel expenses. The present value of the revenue requirement of the facility over 20 years is $1,120 million and $1,335 million over 30 years. The net benefit to customers over the next 30 years is $615 million which is a 78% return for the customers. The inflation adjusted levelized cost of energy for the Low LCOE wind project is around $22/MWh with an expected average benefit price of $37/MWh over the 30 year life.

400 MW of Low and Mid LCOE Wind

The low range of savings in the customer savings plan is based on the assumption that 400 MW of the wind will be added with Mid LCOE wind. The Mid LCOE projects have a higher LCOE due to a lower wind resource assumption than the Low LCOE projects. The Mid LCOE wind has less basis exposure which is the primary factor for the higher realized benefit. In combination, the 400 MW of Low LCOE and 400 MW of Mid LCOE wind are expected to generate a present benefit of $1,346 million over the next 20 years and $1,844 million over the next 30 years. The present value of the revenue requirement of the facility over the 20 year is $1,182 million and $1,414 million over 30 years. The net benefit to customers over the next 30 years is $431 million which is a 56% return for customers. The inflation adjusted levelized cost of energy for the Mid LCOE wind project is around $30/MWh with an expected average benefit price of $40/MWh over the 30 year life.

Retire Asbury

Retiring Asbury will save approximately $40 to $47 million over 20 years in present value discounted at the after tax-weighted average cost of capital rate of 6.59%. Continued operation of Asbury is expected to net $18 million (SPP revenue less coal costs, operation and maintenance costs and property taxes) which is less than the $45 million in future capital costs required to operate the plant until 2035 (includes future return on and income taxes with the projected future capital costs described in Table 8). There are additional property tax savings and savings from the extension of the amortization of Asbury which round out the savings associated with retiring Asbury.

Additional benefits from retiring Asbury are seen when comparing Plan 2, Base 800 Wind, with Plan 4, Base with Asbury. Plan 2, Base 800 Wind saves $75 million over 20 years when compared to keeping Asbury online. The savings increase to $198 million PVRR over 30 years. The removal of Asbury allows for more beneficial and flexible gas units to be built earlier rather than continued operation of the older less efficient Asbury.

Load and Capability Balance Report Update

An additional analysis of each plan was performed to ensure capacity margin requirements of 12% based on summer peak load were met in each year. The generation was calculated based on summer ratings and the accredited capacity as defined by SPP. It was assumed 3 years of data would be available and allowed for wind accreditation.

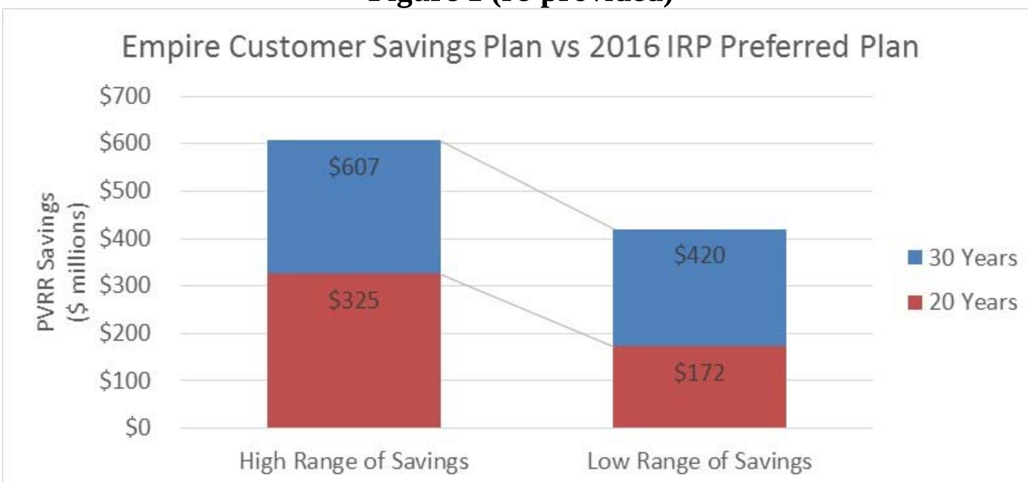
Net Result

As indicated in the results above, it is not surprising to see that customer costs incurred can be decreased from adding 800 MW of new wind utilizing tax equity to reduce the initial capital investment. It is also clear from the savings between Plan 2 and Plan 4 that retiring Asbury to avoid future capital investment is beneficial to customers.

8. Conclusion and Next Steps

The GFSA reflects a potential for significant savings to customers on a 20 or 30 year basis. Figure 1, provided again here reflects a range of $172 million to $607 million.

Figure 1 (re-provided)



To achieve timely realization of these savings, action must be taken now to maximize the value of the Production Tax Credits and avoid $20 to $30 million of environmentally mandated capital investment at the Asbury coal plant.

Finally, this GFSA is being provided in support of Empire's Customer Savings Plan regulatory filing that will be made in Missouri, Kansas, Arkansas and Oklahoma. Empire looks forward to working with regulatory stakeholders to discuss the GFSA and the Customer Savings Plan to achieve significant savings for customers.

PUBLIC VERSION

Generation Fleet Savings Analysis
Appendix 1

The Empire District Electric Company

October 2017

****<u>Denotes Confidential</u>****

PUBLIC VERSION

Table 1

Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)

<u>Confidential in its entirety</u>

(Source: ABB Advisors.)

Table 2

SPP-KSMO 7 x 24 Market Prices for All Scenarios (Nominal $/MWh)

Confidential in its entirety

(Source: ABB Advisors.)

Table 3
Base EDE Coal Price Forecast (Nominal $/MMBtu)
<u>Confidential in its entirety</u>

AFFIDAVIT OF JAMES MCMAHON

COMMONWEALTH OF MASSACHUSETTS)
) ss
COUNTY OF SUFFOLK)

On the 23 day of October, 2017, 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 23 day of October, 2017

Notary Public

My commission expires: 2/9/18

SUZANNE M. WALSH
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS
MY COMM. EXPIRES
FEB. 9, 2018