Exhibit No.: _____
Issue(s): Economic and Regulatory Policies Supporting Recovery of the Remaining Investment in Asbury
Witness: Frank C. Graves
Type of Exhibit: Direct Testimony
Sponsoring Party: The Empire District Electric Company
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Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Frank C. Graves

on behalf of

The Empire District Electric Company

May 28, 2021

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FOR THE DIRECT TESTIMONY OF FRANK C. GRAVES
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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I. INTRODUCTION AND SUMMARY

Q. Please state your name, position, and address.

A. My name is Frank C. Graves. I am a Principal at the Brattle Group. My business address is One Beacon Street, Suite 2600, Boston MA, 02108.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of The Empire District Electric Company ("Empire" or "Company").

Q. Please summarize your educational background and professional experience.

A. For most of my professional career spanning over 30 years as a consultant, I have worked in regulatory and financial economics, especially regarding long-range planning for electric and gas utilities, and in litigation matters related to securities litigation and risk management. My education includes an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

In regard to utility resource planning and cost recovery risks, which are central matters in this case, I have extensive experience in system planning with capacity optimization and production costing models, load forecasting, fuel procurement and risk management, and pollution control compliance. On a number of occasions, I have examined the benefits and prudence of the decision to retire coal-fired power plants and replace them with a portfolio of renewable, storage, and gas-fired peaking resources. Recently, I have focused on evaluating pathways to deep decarbonization of our energy sector as well as the benefits and impacts of distributed energy resources. In regard to customer and financial impacts, I have developed or used many utility financial projections for revenue requirements and rate projections, and I have evaluated financial risk and cost of capital in a wide variety of settings for energy infrastructure and utility investments. My background and qualifications are described in greater detail in the attached **Schedule FCG-1**.

Q. Have you previously testified before the Missouri Public Service Commission ("Commission") or any other regulatory agency?

A. I have given expert testimony on financial and regulatory issues before the Federal Energy Regulatory Commission ("FERC"), many state regulatory commissions, and state and federal courts. This is the first time I have had the opportunity to testify before this Commission.

Q. What is the purpose of your Direct Testimony in this proceeding?

A. I have been asked by Empire to opine on the appropriateness of recovering the undepreciated investments at the Asbury 1 coal-fired unit ("Asbury") from Empire's customers after the retirement of the unit in March 2020. More specifically, I will:

- evaluate the prudency of past major capital investment decisions at Asbury based on then-projected cost savings relative to retirement;
- assess the prudency of the recent decision to retire the unit by reviewing the reasonableness of the modeling approach and results in Empire's 2019 Integrated Resource Plan ("IRP"); and
- summarize the regulatory treatment taken and approved for retiring plants owned by utilities in other jurisdictions, and assess whether the proposed undepreciated

cost recovery mechanism sought by Empire for Asbury is reasonable and appropriate in light of customer benefits, incentives and regulatory policy consistency.

Q. What are your main conclusions?

A. Based on my expertise and experience and my review of Empire's filings and past analyses, I reached the following conclusions.

- Empire's past major capital investments at Asbury were prudently chosen to save costs for Empire's customers and to comply with environmental regulations.
- The recent retirement of Asbury was reasonable and both consistent with recent industry outlook of key market fundamentals and beneficial for Empire's customers. In fact, those costs are reduced not just on a present value basis but in nearly every year of the next two decades, so there is no distributional issue at play.
- Longstanding and economically well-justified ratemaking principles and standards in the utility industry strongly dictate that prudent investments should be fully recoverable from customers, even if they should at some point prove less economic than was originally expected. The question of "balancing of interests" between customers and investors does not contravene here to suggest any kind of disallowance would be equitable or beneficial, even for customers. Here there are many customer benefits to the retirement of Asbury, and any non-recovery would result in an unwarranted windfall to customers that would penalize and discourage prudent decision-making by the Company.
- Other state regulatory commissions have broadly allowed full recovery of prudently incurred past investment costs, including costs such as abandoned construction work in progress and those associated with unusable inventory, when

shifting economics, uncontrollable external changes, and/or new regulatory mandates have caused premature obsolescence.

Q. How is your testimony organized?

A. I first describe the past capital expenditures at Asbury and the conditions that required the selection and installation of the equipment that makes up the large majority of the current undepreciated investments remaining at the plant in Section II. I review the reasonableness of the modeling approach used in Empire's 2019 IRP in Section III and the basis for the expected cost savings from the retirement and replacement of Asbury in Section IV. In Section V, I assess the decisions for Empire's capital investments at Asbury prior to the retirement of the plant, which I find to be reasonable and prudent. I then summarize the regulatory and economic principles underlying appropriate regulatory treatment of plants like Asbury and I describe some examples of such approvals and cost recovery for retiring plants owned by utilities in other jurisdictions in Section VI. All of this leads me to conclude that the proposed cost recovery sought by Empire for Asbury is reasonable and appropriate, as explained in Section VII.

II. PAST CAPITAL INVESTMENTS AT ASBURY

Q. Please summarize your understanding of the undepreciated investments that Empire is proposing to recover.

A. Empire has incurred several major capital expenditures to operate and maintain Asbury over the past 20 years, which have not yet been fully amortized and recovered in rates, so Asbury could continue to operate under federally-mandated environmental regulations. These include:

- $33 million in 2008 for the installation of Selective Catalytic Reduction ("SCR") for the removal of nitrous oxides; and

- $141 million in 2014 (with an additional $1.4 million in total during 2015-2017) for the installation of the Air Quality Control System ("AQCS") which included a dry circulating fluidized bed scrubber for sulfur dioxide removal, powder activated carbon injection system for mercury removal, a pulse jet fabric filter baghouse for removal of particulate matter from the flue gas, and the conversion from a forced draft boiler to a balanced draft. This also includes $21 million investment for a turbine upgrade.[1]

Each of these major investments were reviewed and approved by the Commission.[2]

Additionally, Empire incurred a number of other expenditures. Table 1 depicts the composition of the current net book value of Asbury of capital expenditures. Together, the SCR and AQCS investments listed above account for 73 percent, *i.e.*, the vast majority, of the current total undepreciated investment (*i.e.*, net book value) of $199 million at Asbury.

TABLE 1: CURRENT NET BOOK VALUE AT ASBURY

	Book Cost	Estimated Accumulated Depreciation	Estimated Net Book Value
Asbury AQCS	$142,304,321	$19,843,667	$122,460,654
Asbury SCR	$32,762,867	$9,430,342	$23,332,525
Remainder	$108,057,969	$55,180,986	$52,876,983
Total	**$283,125,157**	**$84,454,995**	**$198,670,162**
AQCS & SCR Share	***62%***	***35%***	***73%***

Sources and Notes: The Empire District Electric Company. Asbury Asset Listing as of February 29, 2020. The $142 million AQCS book cost includes the $21 million investment for the turbine upgrade completed as part of the project. Of the $199 million in estimated net book value, $15.0 million will be generation plant retained for use as part of the various wind projects the Company has under development

[1] The AQCS project also included the retirement of Asbury 2.

[2] *See* Missouri Public Service Commission, Case No. EO-2005-0263 and Case No. ER-2014-0351.

Q. Please describe the conditions that necessitated the installation of SCR at Asbury.

A. The U.S. Environmental Protection Agency ("EPA") issued the final Clean Air Interstate Rule ("CAIR") in March 2005 to address interstate transport of fine particulate matter and ozone (smog), which contributed to downwind states not being able to meet National Ambient Air Quality Standards.[3] CAIR required 28 states, including Missouri, to reduce their emissions of sulfur dioxide ("SO_2") and/or nitrogen oxides ("NO_x").[4] Missouri elected to participate in the EPA-administered cap-and-trade programs for SO_2 and NO_x emissions. The installation of SCR at Asbury helped Empire comply with this regulation, allowing the company to avoid the high cost of purchasing SO_2 and NO_x allowances through the EPA-administered cap and trade system. It is my understanding that the Commission reviewed and approved this plan a few years prior to its actual expenditures and installation.[5]

Q. Please describe the conditions that necessitated the AQCS at Asbury.

A. Empire considered the installation of AQCS retrofits at Asbury in its 2010 IRP to comply with the emerging environmental regulations related to emissions of SO_2, particulates, and mercury.[6] In particular, it was known by 2010 that the EPA would propose air toxics standards for coal-fired generation units in 2011 with expected compliance deadline around 2015.[7] Coal plants not meeting the emission standards by 2015 would have to retire. The EPA in February 2012 issued the final Mercury and Air

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[3] Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_x SIP Call; Final Rule, 70 Fed. Reg. 25161 (May 12, 2005), https://www.federalregister.gov/documents/2005/05/12/05-5723/rule-to-reduce-interstate-transport-of-fine-particulate-matter-and-ozone-clean-air-interstate-rule.

[4] Missouri was one of the 23 states, along with the District of Columbia, required to reduce *both* SO_2 and NO_x emissions.

[5] Missouri Public Service Commission, Case No. EO-2005-0263.

[6] 2010 IRP, Volume III, page 11.

[7] "History of the MATS Regulation," U.S. Environmental Protection Agency, https://www.epa.gov/mats/history-mats-regulation; 2010 IRP, Volume III, page 12.

Toxics Standards ("MATS") limiting the amount of mercury, heavy metals, acid gas, and organic hazardous air pollutants from power plants.[8]

Empire had studied in its 2010 IRP the possibility of retrofitting Asbury to include additional environmental equipment in order to comply with the expected forthcoming regulation. Black & Veatch, an engineering firm, conducted the study, and led the development of technical specifications for the AQCS system. The completion of the AQCS project allowed the Asbury plant to comply with the MATS rule in time for compliance by April 2015, or within the 1-year potential extension from state permitting authorities. Around the same time of the MATS release, the EPA also finalized the Cross-State Air Pollution Rule ("CSAPR"), which replaced the CAIR.[9] CSAPR imposed rules to reduce ozone and fine particulate emissions by reducing SO_2 and NO_x emissions. While legal disputes over CSAPR were still unfolding, Empire expected to meet the CSAPR requirements with the installation of AQCS.

III. REASONABLENESS OF THE 2019 IRP MODELING APPROACH AND RESULTS

Q. Please summarize Empire's resource planning studies over the last five years regarding the economics of the retirement of Asbury and the addition of renewable generation.

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[8] National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule, 77 Fed. Reg. 9303 (February 16, 2012), https://www.federalregister.gov/documents/2012/02/16/2012-806/national-emission-standards-for-hazardous-air-pollutants-from-coal--and-oil-fired-electric-utility.

[9] Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Final Rule and Proposed Rule, 77 Fed. Reg. 10341 (February 21, 2012), https://www.federalregister.gov/documents/2012/02/21/2012-3704/revisions-to-federal-implementation-plans-to-reduce-interstate-transport-of-fine-particulate-matter.

A. Empire has conducted four studies since 2016 to evaluate least-cost resource plans to serve its customers. In the first of these, its 2016 IRP, the outlook for key market fundamentals (fuel and market price outlook, cost of new wind, *etc.*) favored retaining of Asbury until 2035. But starting in the 2017 Generation Fleet Savings Analysis ("GFSA"), the evolution of the Southwest Power Pool ("SPP") market, reductions in forecasted natural gas prices, fairly flat (almost no) load growth, substantial drops in the cost of new wind as well as more creative investment vehicles, and higher wind capacity factors resulted in reducing the economic attractiveness of retaining Asbury beyond 2019 and increasing the attractiveness of adding new wind and solar generation. Specifically, Empire's 2017 GFSA results showed that retiring Asbury by the Spring of 2019 and replacing it with 800 MW of new wind generation would result in $325 million in 20-year present value revenue requirement ("PVRR") savings under the base case outlook for its customers compared to the 2016 IRP Preferred Plan which did not have the 800 MW of wind and which retained Asbury until 2035.[10]

Similarly, Empire's 2018 IRP Update preferred Asbury retirement, with an estimated $169 million 20-year PVRR savings from retirement of Asbury in 2019 and replacement with 600 MW new wind compared to retaining Asbury until 2035.[11] While the issue of the retirement of Asbury was deferred for future consideration, the Commission found that Empire had "made reasonable decisions to acquire up to 600 MW of wind" and authorized the Company to record the capital investment as utility plant in service in its July 2018 report and order.[12]

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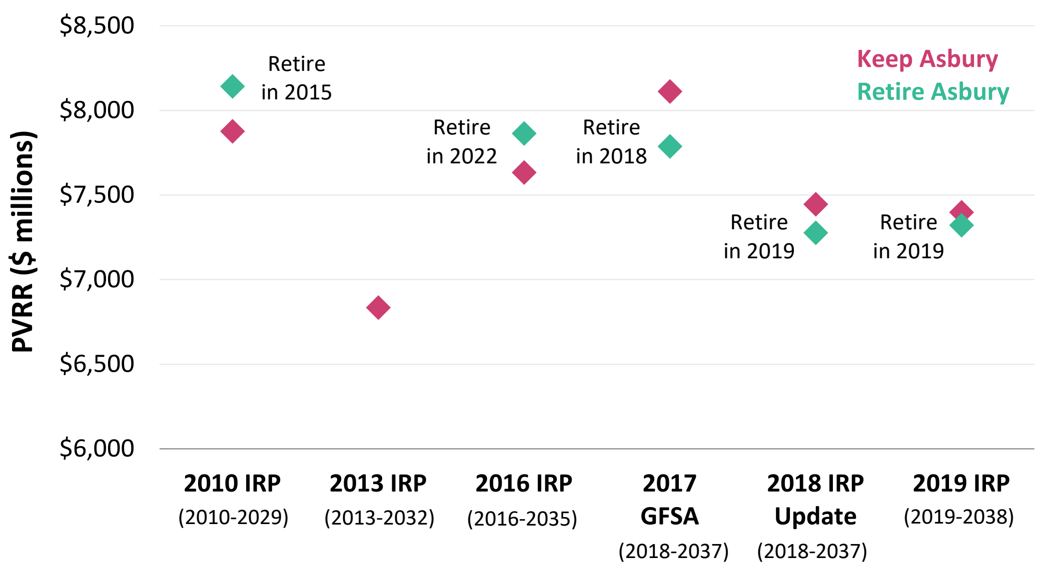
[10] 2017 GFSA, page 1.

[11] 2018 Notice of Change in Preferred Plan, page 8.

[12] *In the Matter of the Application of The Empire District Electric Company for Approval of its Customer Savings Plan*, Report and Order, Docket No. File No. EO-2018-0092, July 11, 2018, pages 15 and 24.

Finally, Empire's 2019 IRP confirmed the findings from both the 2017 GFSA and 2018 IRP Update that the retirement of Asbury would save costs for its customers in the reference case and on an expected value basis, as I explain in further detail below. Figure 1 below presents a comparison of the ranges for projected 20-year PVRRs from retaining Asbury through 2035 (or beyond) in each of those IRPs and additional ones going back to 2010. This shows the evolution of the relative value of the plant over time, with retaining Asbury being preferred to retiring until 2016 but retiring Asbury becoming less expensive starting in 2017.[13] This transition is understandable in light of changes in market fundamentals and new opportunities to invest in new wind more economically that emerged in that year.

FIGURE 1: EVOLUTION OF THE PROJECTED 20-YEAR DETERMINISTIC PVRR FOR THE RETIREMENT OF ASBURY RELATIVE TO KEEPING THE PLANT ONLINE



Sources and Notes: 2010 IRP, Volume V, Table F-6; 2013 IRP, Volume 6, Appendix 6J; 2016 IRP, Volume 6, Appendix 6J; 2017 GFSA, Table 15; 2018 IRP Update, Figure 3; 2019 IRP, Volume 6, Appendix 6J.

[13] Note that the PVRR values shown on the chart reflect the projected costs under the deterministic reference case outlook in each study. The projected PVRRs on an expected value basis (*i.e.*, probability-weighted average of PVRRs across sensitivity cases) were similar to the deterministic PVRR projections and showed a similar pattern over time to the deterministic values shown on the chart.

Q. Please explain Empire's basis for its ultimate decision to retire and replace Asbury.

A. The performance value of the Asbury plant began to deteriorate around 2015, in terms of its utilization, operating cost per megawatt hour ("MWh"), and profitability relative to market prices in the SPP. Thus, in its 2019 IRP, Empire developed 16 alternative resource plans to be evaluated to determine if it should be retained vs. retired and possibly replaced. These are summarized in broad strokes in Table 2 below.

Plan 4, in which Asbury was to be retired at the end of 2019 and replaced with a mix of solar and solar-plus-storage, was selected as the Company's Preferred Plan, leading to the situation faced in this proceeding as to how to address the recovery of its undepreciated past investment costs. Here, I will review some of the key modeling assumptions that went into that analysis and describe how they are consistent with good industry practices for resource evaluation. That is, I will explain why retirement of Asbury was a prudent decision that results in an expected net benefit to customers even after accounting for those customers continuing to pay the pre-tax return on the retired plant.

TABLE 2: SUMMARY OF ALTERNATIVE RESOURCE PLANS

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

Sources and Notes: 2019 IRP, Volume 1, Table 1-2. DSM – Demand-side Management; RAP – Realistic Achievable Potential; MAP – Maximum Achievable Potential.

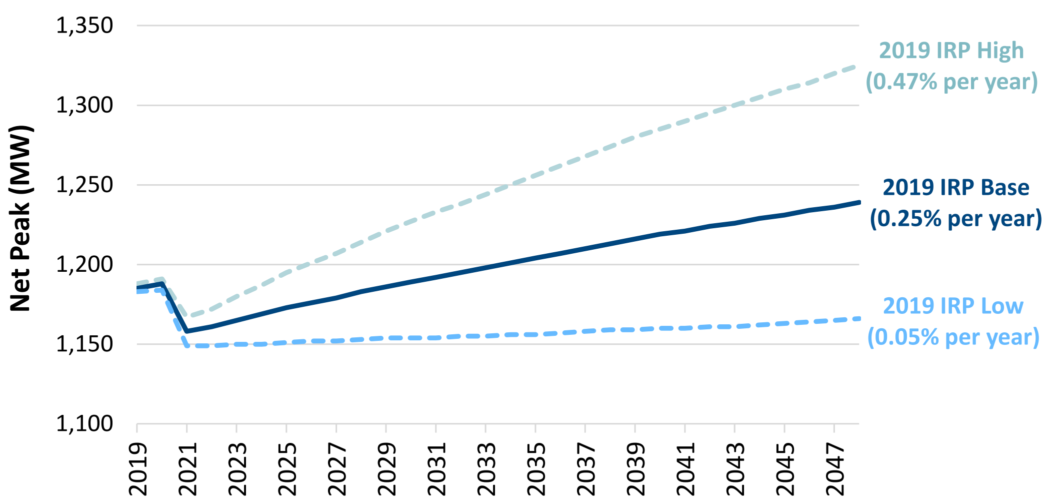
Q. Please describe the modeling inputs and assumptions used by Empire and how they compared to industry expectations at the time of the 2019 IRP.

A. As is appropriate for resource planning, Empire used recognized sources for its key assumptions but also considered the uncertainty surrounding key factors such as load growth rates, fuel prices, carbon prices, and capital costs in order to assess the expected benefits and associated risks of each of the alternative resource plans. I discuss each of these briefly below.

Load Forecast and Resulting Timing for New Capacity

During the period 2015 – 2019, load growth for Empire had been -0.8% per year.[14] In this context, the 2019 IRP projected modest peak growth of 0.25% per year in its base case scenario after the loss of a few municipalities in 2019,[15] as shown in dark blue in Figure 2 below. The North American Electric Reliability Corporation ("NERC") was projecting slightly higher rates of peak demand growth for the broader market area, SPP, in which Empire operates the plant for the 2020–2029 period (0.6% per year), while in this period the IRP's projected demand is essentially flat.[16] A higher load forecast would likely have been more favorable for the economics of keeping Asbury online, and this possibility was also evaluated for the high load growth scenario shown in aqua below.

FIGURE 2: COMPARISON OF WINTER PEAK ASSUMPTIONS IN THE 2019 IRP



Sources and Notes: 2019 IRP, Volume 3, Table 3-67.

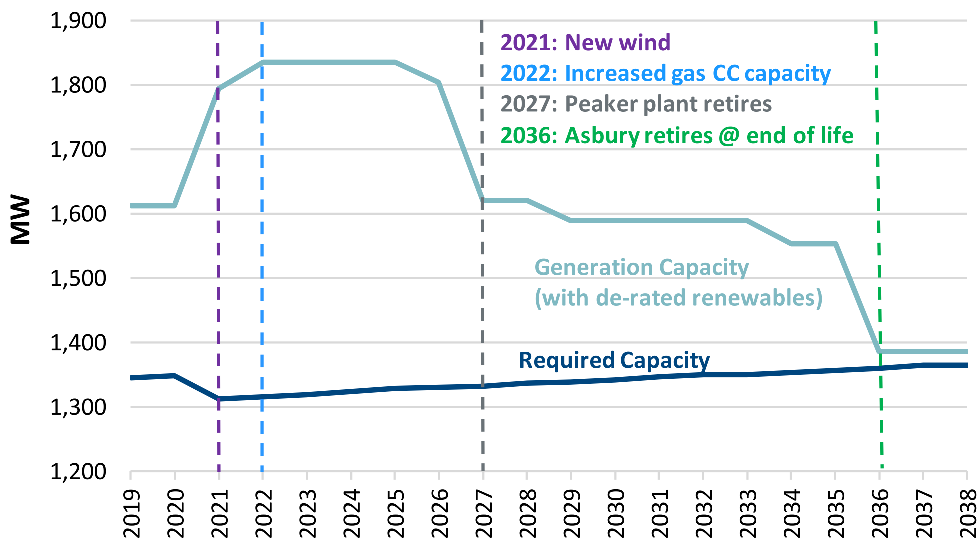
[14] 2019 IRP, Volume 3, Table 3-45; 2020 IRP Annual Update, page 11. Empire also had 111 MW of capacity purchases, implying a total system capacity of 1,613 MW. *See* 2019 IRP Volume 3, Table 6-15.

[15] Compounded annual growth rate from 2021 to 2048. *See* 2019 IRP, Volume 3, Table 3-67.

[16] North American Electric Reliability Corporation, "2019 Long-Term Reliability Assessment," December 2019, page 40, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf.

In 2019, Empire had a total net winter capacity of 1,502 MW including Asbury, relative to a peak load of 1,111 MW.[17] This capacity situation combined with the modest growth forecast described above resulted in Empire being "long" in capacity during the 20-year planning window, with or without Asbury or any replacements for it. That is, it was expecting to have reserve margins until 2038 that would remain consistently above the 13.6% reliability requirement, as shown in Figure 3 (with Asbury) and Figure 4 (without) below.[18] This indicates that at least in regard to resource adequacy, there was no further need for the coal plant.

FIGURE 3: 2019 IRP PLAN 1 WINTER CAPACITY BALANCE
(With Asbury until 2036)



Sources and Notes: 2019 IRP, Volume 6, Table 6-15. Required capacity = (peak load with demand-side management) × (1 + 13.6% reserve margin). Capacity credits for wind, solar, and solar-plus-storage are 30%, 5%, and 24%, respectively.

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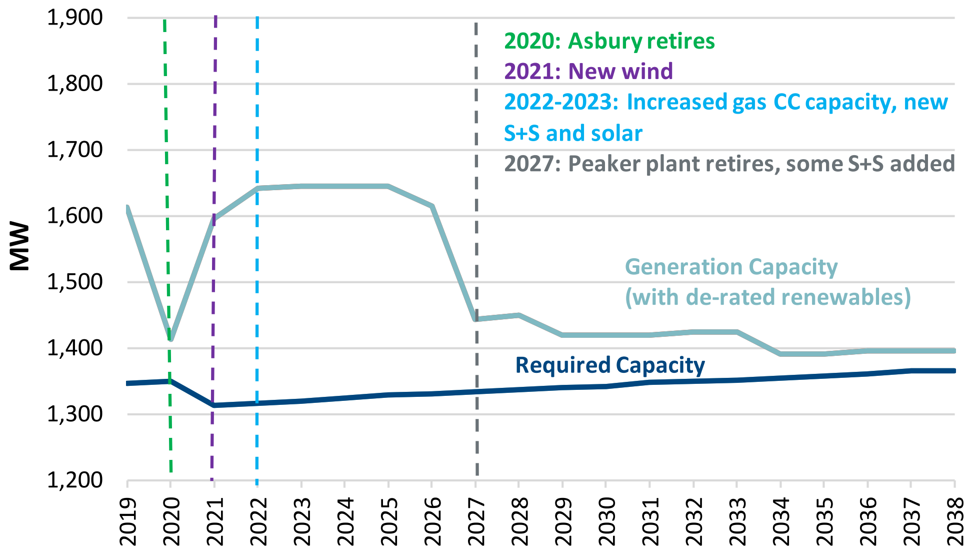
17 2019 IRP, Volume 6, Table 6-15; 2020 IRP Annual Update, page 11.

18 Capacity shortfalls are not the only reason for adding or retaining vs. retiring capacity. New capacity may also be important for energy cost savings or environmental benefits (or both) as here for the new wind units Empire is adding. (Also, wind units are not comparable in capacity performance to a fossil unit.)

FIGURE 4: 2019 IRP PREFERRED PLAN WINTER CAPACITY BALANCE

(With Asbury Retiring in 2020)



Sources and Notes: 2019 IRP, Volume 6, Table 6-25. Required capacity = (peak load with demand-side management) × (1 + 13.6% reserve margin). Capacity credits for wind, solar, and solar-plus-storage are 30%, 5%, and 24%, respectively.

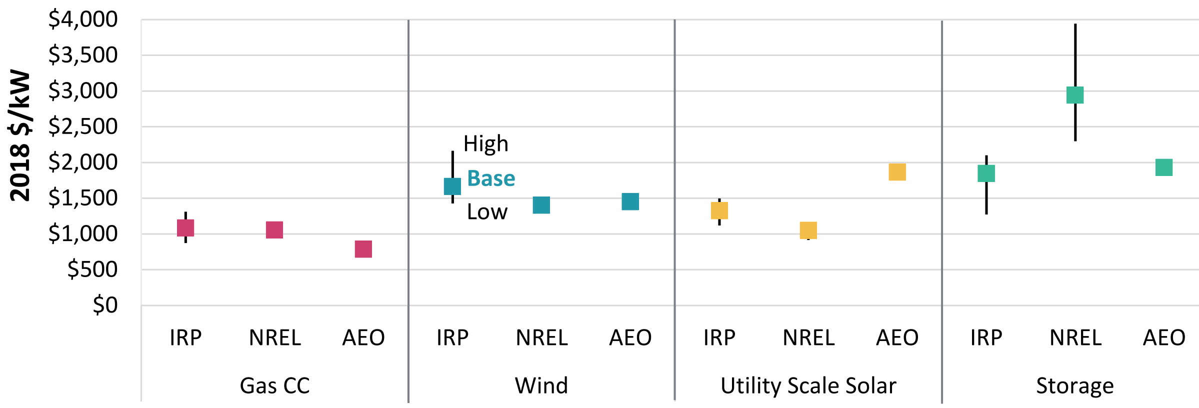
Capital Costs

Several types of new generation capacity to replace Asbury (if needed) were considered in the 2019 IRP. The capital cost assumptions Empire used to evaluate these were largely consistent with (or a bit higher for gas combined cycle ("CC") and wind) industry estimates, based on comparison to then available projections from the National Renewable Energy Laboratory ("NREL") and the U.S. Department of Energy ("DoE") Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") and reflect typical treatment of capital expenditures for replacement technologies when performing resource planning.[19] The higher capital costs for the gas CC and wind in Empire's study makes Empire's finding of cost savings from retiring Asbury

[19] U.S. Energy Information Administration, "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2019," January 2019, https://www.eia.gov/outlooks/archive/aeo19/assumptions/pdf/table_8.2.pdf.
"2018 Annual Technology Baseline," National Renewable Energy Laboratory," https://atb.nrel.gov/electricity/2018/index.html.

conservative. Empire's IRP finds that the lowest cost resources to replace Asbury's power are new solar and storage, whose cost estimates were reasonable. Figure 5 below shows these costs for the different types of generation capacity.

FIGURE 5: COMPARISON OF CAPITAL COST ASSUMPTIONS IN THE 2019 IRP



Sources and Notes: 2019 IRP installed capital costs, AEO 2019 regional overnight capital costs, and NREL 2018 overnight capital costs (adjusted based on AEO regional multipliers). NREL storage costs reflect installed capital costs.

Natural Gas Prices

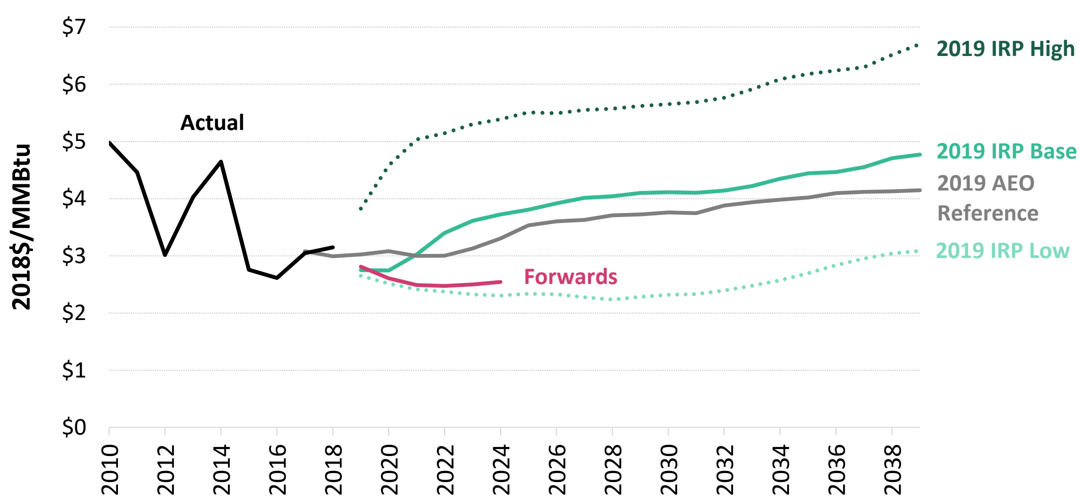
One of the most important assumptions of a resource plan is the expected trajectory and range of alternatives considered for the future price of natural gas. This is important because gas-fired generation is often "on the margin" (last dispatched to serve load) in power markets including SPP, hence often setting the market price of energy.[20] There are several sources for these gas price outlooks, including commercial forecasting

[20] Power plants are scheduled and "dispatched" to collectively always provide the right amount of power needed across a large area (power system) at any instant in time. This is done using sophisticated system simulation tools to identify which plants would be the least costly to use in any minute to satisfy total load taking into account which ones can be so utilized without overloading any of the transmission wires that deliver the power to customers. The result of this process is generally to use the cheapest plants first (often hydro or renewables like wind and solar, which have no fuel cost at all), then nuclear, and then whichever of coal or efficient gas plants are next cheapest (which can change over time as fuel prices move), and finally inefficient older plants or plants burning much more expensive fuels like oil. In a market region like SPP, the marginal costs of the last plant utilized in any hour sets the market price for power paid to all the units then operating, subject to some additional adjustments for satisfying transmission constraints (if any).

services, the publications of the U.S. DoE's EIA, and forward prices for gas trading at large hubs adjusted for basis differential costs to the generation sites.

Here, Empire used gas price forecasts based on the ABB Power Market Advisory database. Figure 6 shows that the base Henry Hub gas price forecast in the 2019 IRP (in solid green) is largely consistent with the 2019 AEO reference case projections (in grey). Average annual forwards as of January to March 2019 (shown in pink) were lower than the 2019 IRP base forecast (and in fact more consistent with the low gas price forecast in the 2019 IRP), suggesting conservatism in this analysis, because lower gas prices would tend to reduce how frequently Asbury would be attractive and profitable relative to market prices.

FIGURE 6: COMPARISON OF HENRY HUB GAS PRICE OUTLOOKS IN THE 2019 IRP

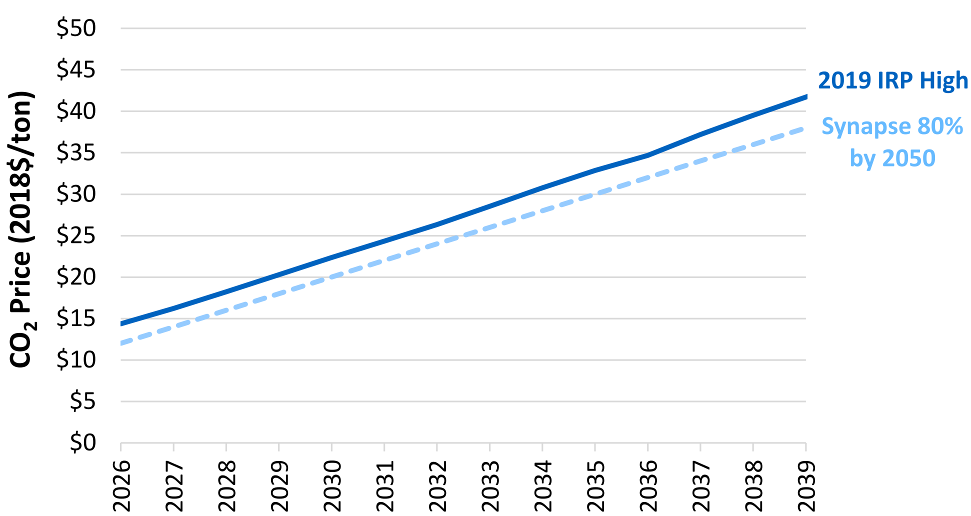


Sources: 2019 IRP, Volume 4, Table 4-18; AEO 2019; S&P Global Market Intelligence. Average annual forwards as of January to March 2019.

Carbon Prices

Carbon dioxide ("CO_2") emissions are not formally priced or penalized in SPP or in Missouri, but nearly every utility in the U.S. has, for the past 10-20 years, included a penalty surcharge in their resource planning studies to reflect an estimate of the social costs of global warming and/or the price at which the utilities expect such emissions may eventually be penalized in state or federal policies. Empire included two carbon scenarios, each weighted with a 50% probability: a base scenario with no carbon price and a scenario that assumes CO_2 prices would be in place in the mid-2020s, at levels consistent with common industry benchmarks for U.S. utility resource planning. Specifically, the 2019 IRP's carbon price forecast (shown in solid blue in Figure 7 below) is based on a Synapse analysis of the carbon price needed to reach the 80% by 2050 CO_2 reduction target consistent with the Paris Accord (shown in dashed light blue).[21]

FIGURE 7: COMPARISON OF CARBON PRICES IN THE 2019 IRP



Sources: 2019 IRP, Volume 4, Figure 4-17; 2019 IRP, Volume 6, pages 6-42 to 6-43; Nina Peluso, "The Price of Emissions Reduction: Carbon Price Pathways through 2050," Synapse Energy Economics, November 15, 2018, Figure 2, $60 by 2050 case, https://www.synapse-energy.com/about-us/blog/price-emissions-reduction-carbon-price-pathways-through-2050.

[21] 2019 IRP, Volume 4, page 4-82; Nina Peluso, "The Price of Emissions Reduction: Carbon Price Pathways through 2050," Synapse Energy Economics, November 15, 2018, Figure 2, $60 by 2050 case, https://www.synapse-energy.com/about-us/blog/price-emissions-reduction-carbon-price-pathways-through-2050.

Q. Please describe the modeling techniques and tools used by Empire in its 2019 IRP.

A. Empire used three levels of modeling tools in its 2019 IRP. First, for its market-area simulation, the company relied on ABB's integrated energy market models to develop natural gas, coal, and power prices for SPP. Second, these results became inputs, along with additional assumptions for load, emissions prices, and new resource capital costs and the details of each alternative resource plan, to the Aurora planning model, which was used to perform portfolio optimization. Aurora finds the least-cost supply expansion plan by minimizing the PVRR across a selection of available resource options. Each portfolio is evaluated in an hourly, chronological dispatch analysis of the selected resources' use in the SPP market by Aurora. Third, the output of this step was then used in a propriety financial module developed by Empire's consultant, Charles River Associates, to perform utility accounting and to express the plant and system costs on the basis of annual revenue requirement calculations.[22]

This process was repeated for the base case and stochastic (probabilistic scenario) combinations of the various high/low future conditions for each major input assumption described above. The ultimate preference for a resource plan is based on what plan has the lowest base case PVRR and the greatest robustness for that ranking across risk conditions.

Q. Do you consider Empire's modeling approach and assumptions used in the 2019 IRP to be reasonable?

A. Yes. Empire's multi-stage modeling and optimization approach to assess the economics of the retirement of Asbury and replacement with a combination of solar/solar-plus-storage was comprehensive. Aurora is a reputable simulation software widely used by

[22] 2019 IRP, Volume 6, pages 6-129 to 6-133.

others in the industry for resource planning and market forecasts, and all major assumptions and sensitivities were largely consistent with industry expectations at the time of the 2019 IRP.

IV. EXPECTED COST SAVINGS FROM RETIREMENT AND REPLACEMENT OF ASBURY

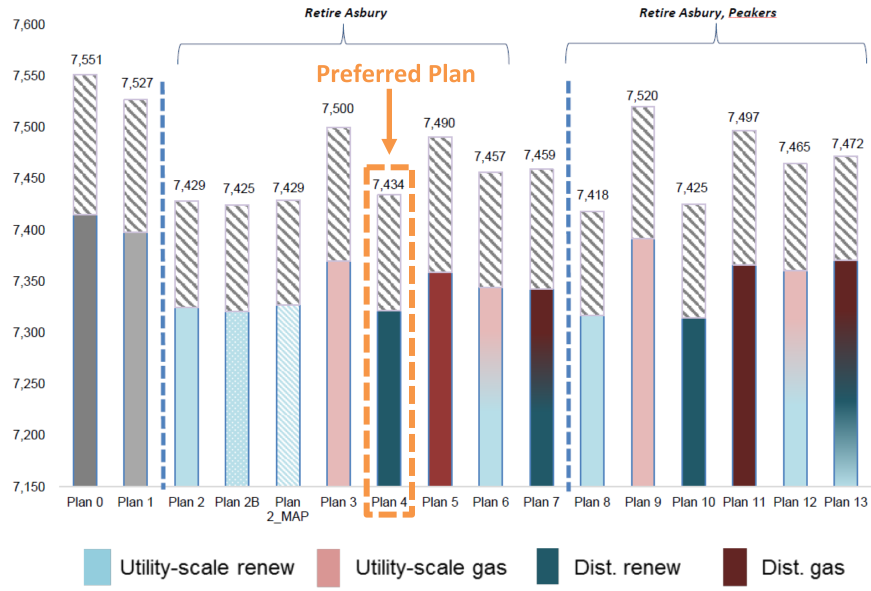
Q. Please explain the cost savings and robustness analysis results that Empire found in that 2019 IRP.

A. Empire measured the cost savings by comparing the net present value ("NPV") of long-run costs required to serve retail customer loads over a 20-year planning period across each of the 16 alternative plans summarized in Table 2 above. The Company considered risks associated with the uncertainty around load growth, fuel prices, carbon prices, and capital costs to evaluate their impact on each of the alternative resource plans.[23] This analysis determined that retiring Asbury in 2019 and replacing it with a mix of solar and storage would result in PVRR savings relative to operating the plant until 2035, finding \$93 million of benefit from retirement on a 20-year *expected value basis* (*i.e.*, probability-weighted average across the sensitivity cases) as shown in Figure 8.[24]

[23] 2019 IRP, Volume 1, page 1-33.

[24] 2019 IRP, Volume 7, pages 7-10 to 7-12. Asbury is replaced with solar/solar-plus-storage upon retirement at end of life in 2035 in Plan 1.

FIGURE 8: PVRR WITH RISK VALUE FOR ALL PLANS IN 2019 IRP (2019–2038)



Source: 2019 IRP, Volume 7, Figure 7-3.

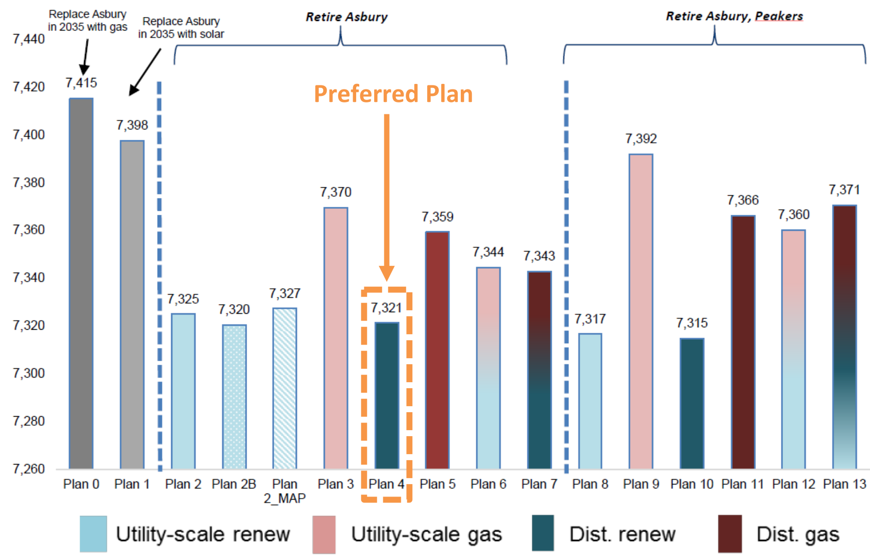
Q. What are the key components of the PVRR savings when comparing the Preferred Plan to keeping the plant through 2035 in Plan 1?

A. In order to understand the drivers of the PVRR savings, it is more instructive to look specifically at the scenario that Empire modeled with its base case assumptions for load growth, fuel prices, carbon prices, and capital costs. This analysis determined that retiring Asbury in 2019 and replacing it with a mix of solar/solar-plus-storage would reduce the PVRR by $76 million (from $7,398 million to $7,321 million) on a 20-year *deterministic basis*[25] compared to operating the plant until 2035 under its original life, as occurs in Plan 1,[26] shown in Figure 9 below.

[25] The projected savings on a *deterministic basis* reflect PVRR reductions under a single, fixed set of base case assumptions for future market fundamentals (such as load growth and fuel prices). In contrast, the projected savings on an *expected value basis* reflect the probability-weighted average of PVRR savings over multiple scenarios/sensitivities spanning a wide range of possible realized values for those future market fundamentals.

[26] 2019 IRP, Volume 7, pages 7-10 to 7-12. In Plan 1, Asbury is replaced with solar-plus-storage upon retirement at the end of its life in 2035.

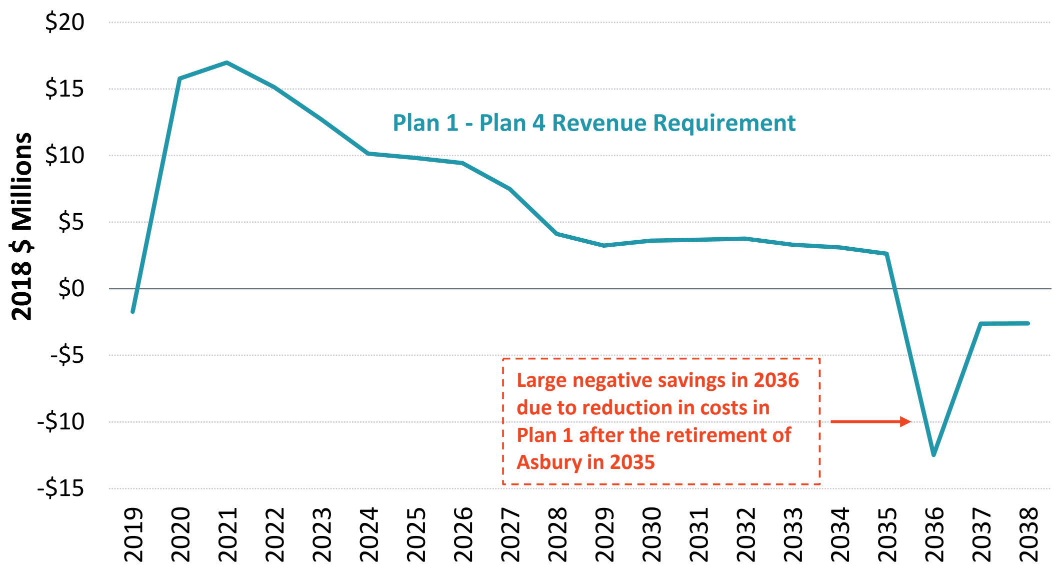
FIGURE 9: DETERMINISTIC PVRR FOR ALL PLANS IN 2019 IRP (2019–2038)



Source: 2019 IRP, Volume 7, Figure 7-1.

Notably, the PVRR savings from the Preferred Plan arise almost immediately and occur with only a slow annual decline over all of the next 15 years after the retirement of Asbury. This is not a highly deferred future benefit that might be considered speculative if dependent on many complex future conditions. The annual revenue requirement savings in the Preferred Plan relative to Plan 1 (which retains Asbury until 2035) are shown below in Figure 10.

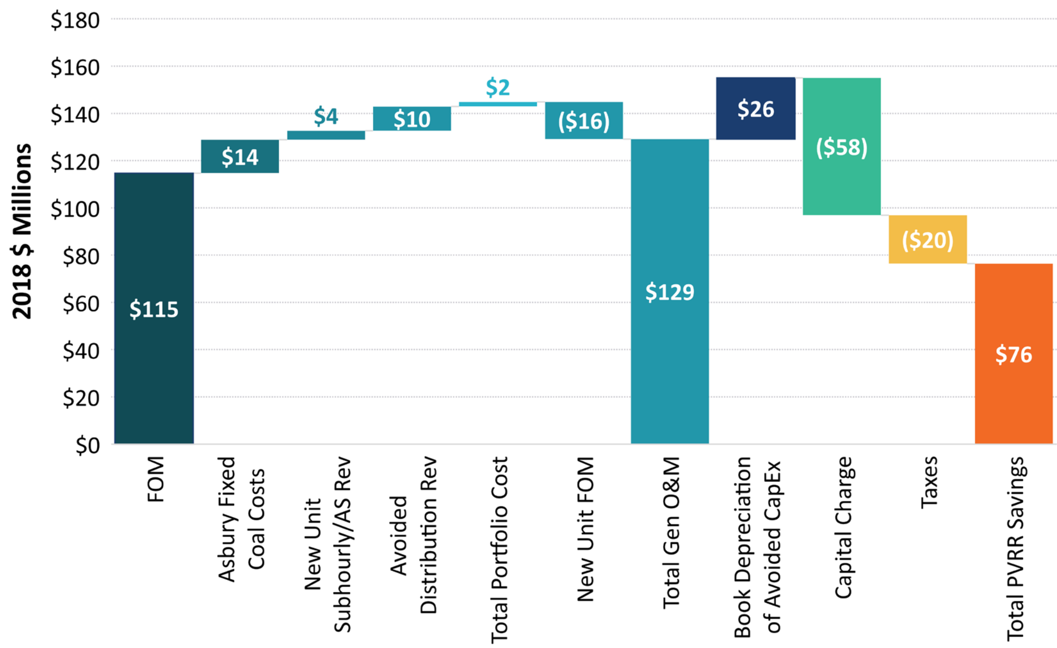
FIGURE 10: ANNUAL REVENUE REQUIREMENT SAVINGS FROM THE RETIREMENT OF ASBURY



Source: 2019 IRP, Data Response 0017.

The majority of the $76 million in base case, deterministic PVRR savings is driven by a $129 million reduction in total (system-wide) generation operations and maintenance ("O&M") costs and $26 million reduction in book depreciation costs. The reduction in total generation O&M costs are lower largely due to avoiding $115 million of Asbury fixed operations and maintenance ("FOM") costs and Asbury fixed coal costs. The reduction in book depreciation costs arises from $46 million in savings for longer depreciation life of undepreciated past investment costs at Asbury in the Preferred Plan, partly offset by $20 million increased depreciation costs associated with new resources in the Preferred Plan. These savings are offset partly by a $58 million increase in capital charge costs, which stem from return on and of new solar and storage coming online after the retirement of Asbury. Figure 11 below illustrates these savings and cost components.

FIGURE 11: TOTAL SYSTEM PVRR SAVINGS FROM THE RETIREMENT OF ASBURY



Source: 2019 IRP, Data Response 0017.

Q. Did Empire evaluate the projected performance of Asbury against future market conditions if the plant had continued to operate?

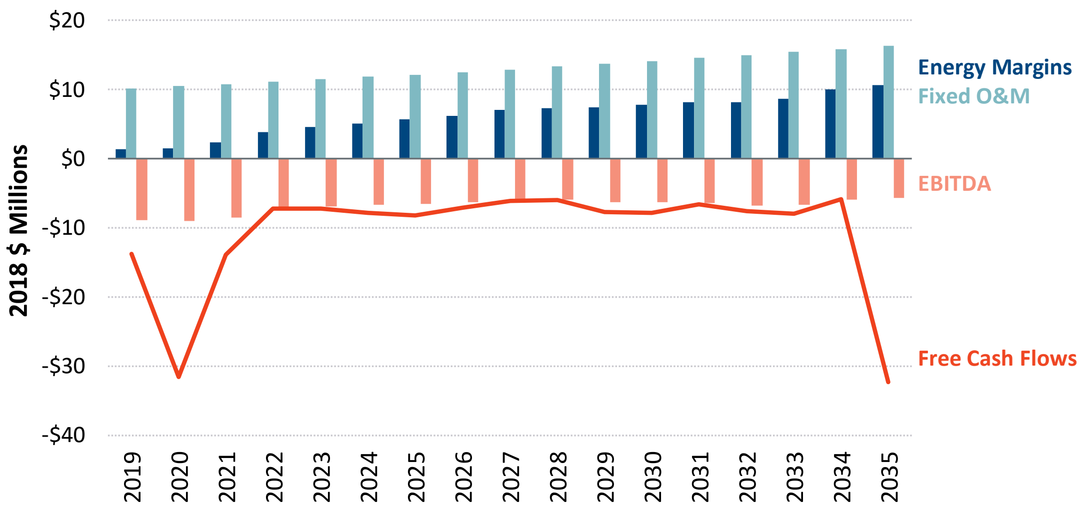
A. Yes. The 2019 IRP forecasted Asbury operations to result in continuing losses if it were not retired, with negative free cash flows totaling -$113 million in net present value through 2035 (assuming 6.71% discount rate).[27] The projected energy margins and free cash flows for the unit over time are shown in Figure 12 below.[28] Projected energy margins for the plant are small in the near term (about $2 million or $4/MWh) and increasing to about $11 million ($13/MWh) in 2035. But the fixed O&M costs (about $13 million per year on average) exceed these projected energy margins, hence resulting in negative EBITDA values. The annual free cash flows include the additional capital

27 Discount rate based on Empire's after-tax weighted average cost of capital ("ATWACC"). *See* 2019 IRP, Volume 6, page 6-18.

28 The margins shown in this analysis does not attribute any capacity value to Asbury for this period, since Empire was projected to be long in capacity in Plan 1 until Asbury retires in 2036.

investments Asbury would have needed in the near-term to operate past October 2020 – in the order of approximately $20 million – for the construction of a new landfill and to convert the existing bottom ash handling from a wet to dry system in order to comply with the EPA's rule on the disposal of coal combustion residuals.[29]

FIGURE 12: PROJECTED OPERATING MARGINS FOR ASBURY



Sources and Notes: 2019 IRP, Data Responses 0017 and 0020. Earnings before Interest, Taxes, Depreciation, and Amortization ("EBITDA") = Energy Margins – Fixed Operations and Maintenance ("O&M"). Free Cash Flows = Energy Margins – Fixed O&M – Ongoing Capital Expenditures ("CapEx"). Ongoing CapEx does not include Black & Veatch additions in 2020 Fair Market Valuation study.

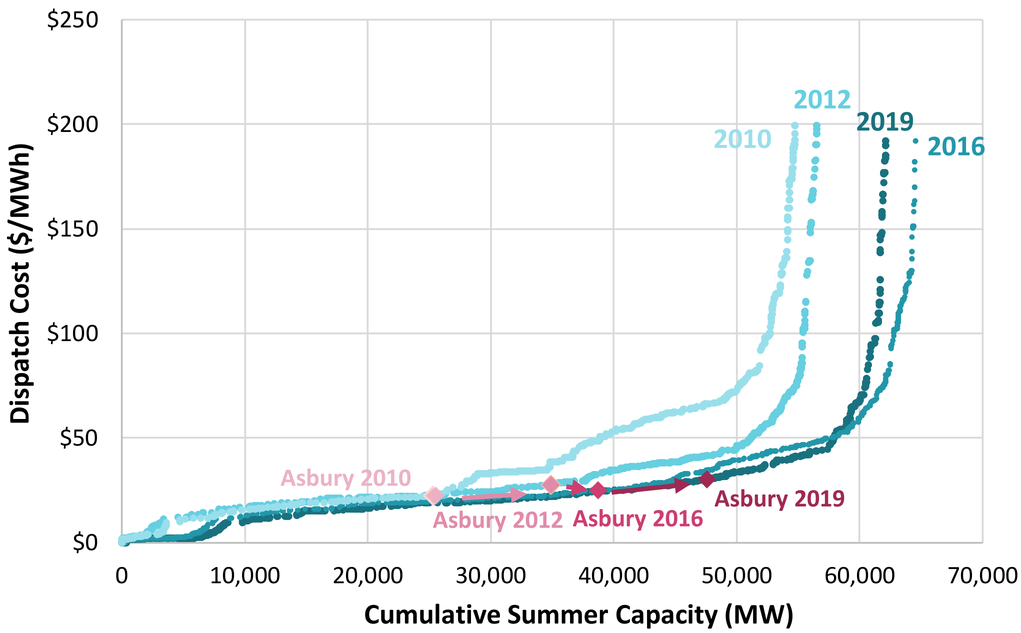
Q. How did changing market conditions between 2010 and 2019 lead to Asbury's declining economic performance against the market and a reversal of the previously expected need for the plant?

A. There were many significant changes in market fundamentals that occurred in the last decade affecting SPP and most of the electric industry. An overview of these consequences is seen in Figure 13 below, which shows how Asbury's position on the SPP supply curve has gotten progressively worse in the past decade (moving farther out the curve towards more expensive plants with relatively less usage), primarily due to

[29] 2019 IRP, Volume 1, page 1-9; 2019 IRP Volume 6, page 6-26.

decreasing gas prices and the declining cost and increasing penetration of renewable generation.

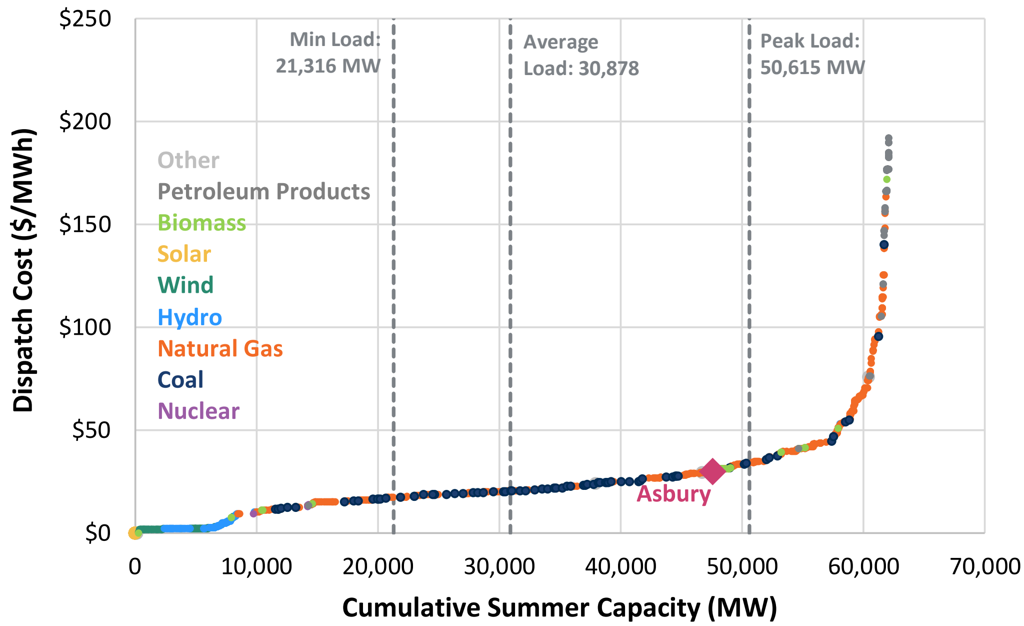
FIGURE 13: SPP SUMMER SUPPLY CURVES IN 2010, 2012, 2016, AND 2019



Sources and Notes: S&P Global Market Intelligence, data as of November 18, 2020. Units are assigned the following capacity credits: 95% for nuclear; 90% for hydro, coal, gas, and oil, 80% for solar, and 20% for wind.

A closer inspection of the 2019 supply curve by fuel type, in Figure 14 below, shows that Asbury's marginal cost had become higher than the majority of coal units in SPP (dark blue points in the supply curve) and is on the expensive end more generally – *i.e.*, fairly close to the end of the dispatch ladder needed to serve peak load – making the unit uneconomic to run in a large number of hours. (The curve is color coded by type of fuel to reveal the merit order of dispatch.) This is not because of something going wrong with the unit but because (as explained more fully below) of the mostly unexpected sustained low gas prices and higher penetration of renewable generation driven by their continued substantial cost reductions. The latter is precisely what Empire is now taking advantage of on behalf of its customers.

FIGURE 14: 2019 SPP SUMMER SUPPLY CURVE



Sources and Notes: S&P Global Market Intelligence, data as of November 18, 2020. Units are assigned the following capacity credits: 95% for nuclear; 90% for hydro, coal, gas, and oil, 80% for solar, and 20% for wind.

Q. What were the major industry and SPP changes that caused this declining usefulness of the Asbury plant?

A. The economic viability of existing coal plants all around the U.S. began deteriorating in the early part of the last decade largely as a result of decreasing wholesale power prices and increasing costs for coal plants to comply with major federal environmental regulations that imposed tightening emission standards and required coal plants to install and operate emissions control equipment. While the environmental retrofits needed to satisfy regulations such as the EPA's Mercury and Air Toxics Standards were expected in the industry as early as 2010, the realized levels and ongoing future expectations of low wholesale power prices were not foreseen at the beginning of the last decade and indeed their persistence has been somewhat of a surprise for the past several years.

Lower wholesale power prices were driven by three major, roughly concurrent developments that appeared in the beginning of the last decade: (i) the continued and sustained decline in natural gas prices; (ii) a broad market and political/regulatory shift towards more renewable generation;[30] and (iii) slowing growth in electric consumption. The combination of these factors lowered the cost of generation from gas-fired and renewable generation plants relative to coal plants, reduced the need for capacity and energy generation from coal plants, and lowered the wholesale power prices or system marginal costs for both energy and capacity in many regions.

As a result of these broad trends, approximately a third of the U.S. coal fleet that was operating in 2012 has now retired, and another 55 GW (about a quarter of the remaining coal generation) are slated to do so over the next 10 years.[31]

Q. Do you consider Empire's analyses of cost savings and its resulting decision to retire and replace Asbury to be reasonable?

A. Yes. Empire's modeling techniques were comprehensive, and the Company's scenario-based and stochastic evaluations of the potential cost savings under key uncertainties in the future provided a robust analytical basis to stress-test the economic performance of the retirement of Asbury for Empire's customers. The conditions that led to Asbury becoming uneconomical were not foreseen as likely to occur so rapidly or deeply by experts throughout the industry, and Empire's analyses of the associated risks and changes were timely and credible.

The new resources (mostly much smaller and deferred) that will eventually replace Asbury are more economical than Asbury would have been, and market trends are likely to make that finding even stronger in the future, as renewable costs continue

[30] It is certainly the case that the capital and operating costs of renewable resources had been visibly falling for the decade before 2010, but in nearly all cases it was not competitive with conventional fossil fuels so had not yet had a big impact on power markets.

[31] Velocity Suite, ABB Inc., data as of February 18, 2021.

to decline and recent market conditions are probably softer than they were foreseen to be in 2019. In addition, the public pressure to shift away from fossil fuels is certainly going to persist and may well strengthen over the next several years, further depressing the economic value (or regulatory acceptability) of coal plants.

Q. You have described Empire's modeling in its 2019 IRP indicating that the resource plan with the retirement of Asbury would lower the future costs for its customers. Did Empire also take into account the continued recovery of undepreciated past investment costs at Asbury under that resource plan?

A. Yes. Empire concluded that retiring Asbury would save so much costs in the future that customers would remain better off (lower rates) even with continued full cost recovery of the past investments.

V. <u>PRUDENCE OF INVESTMENT DECISIONS PRECEEDING RETIREMENT</u>

Q. Please review the past investments that comprise the majority of the current undepreciated investment balance at the Asbury plant.

A. The plant has a current (February 2020) net book value ("NBV") of unrecovered investment of $199 million. As I described in Section II, the majority (73%) of this NBV is from the 2014 AQCS retrofits ($122 million) and the 2008 SCR retrofit ($23 million). In this section, I provide my assessment of the prudency of the decisions underlying these two retrofits, which account for about three quarters of the total undepreciated past investment balance for Asbury. As I explain below, these decisions were made under economic conditions that were considerably different than today, and the type of conditions that now prevail were at best considered an unlikely scenario a decade or so ago when these retrofits were under consideration. I discuss them in order of size of remaining NBV, beginning with the more expensive AQCS.

A. AQCS Retrofits

Q. How did Empire evaluate the projected cost savings for its customers from the AQCS retrofits at the time of that investment decision?

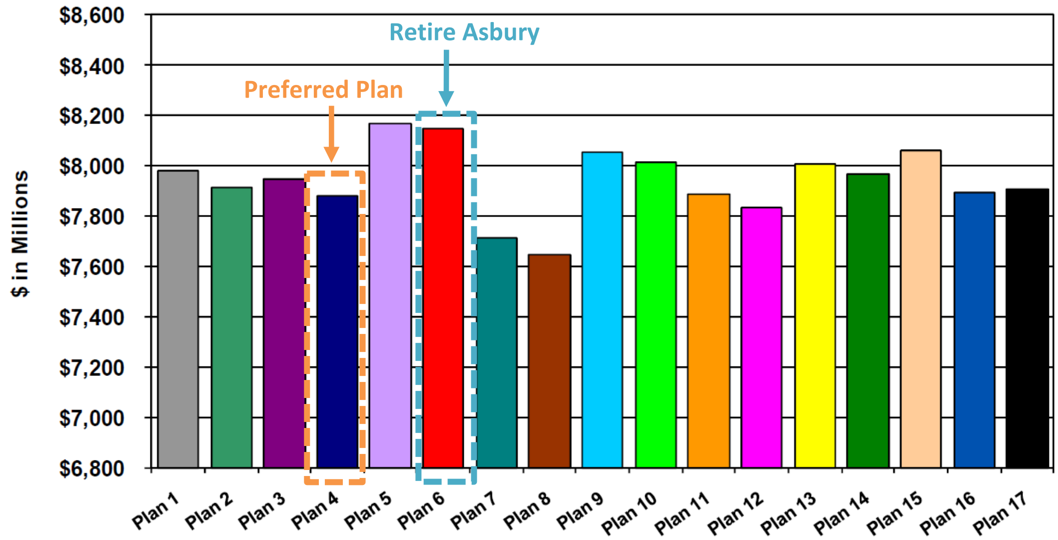
A. In its 2010 IRP analysis, Empire evaluated the potential cost savings from installing the AQCS retrofits to continue operating Asbury compared to retirement in 2015. At that time, the Asbury plant was expected to operate through 2035. The capital cost of the AQCS project was estimated to be $158 million, though that amount was not certain at the time since the full engineering analysis of the project was not yet completed.[32]

The 2010 analysis concluded that the AQCS option (Plan 4, or "the Preferred Plan") would <u>save</u> approximately $267 million for customers in 20-year PVRR compared to retiring Asbury in 2015 and replacing it with a new gas combined-cycle generation plant (Plan 6).[33] The comparison of the deterministic PVRRs across all plans modeled is shown in Figure 15 below.

[32] 2012 IRP Annual Update, pages 10 – 11.

[33] 2010 IRP, Volume V, Table F-6. Plans 1–6 represent resource plans under base assumptions. Plan 7 and Plan 8 are the same as Plan 1 and Plan 2, respectively, except for assuming lower future load due to removing Monett load. Plans 9-17 assume retaining Asbury under various sensitivities for CO_2 prices, fuel prices, and load growth. Thus, these plans are not lower in PVRR because they include a more economical resource mix but because they assume different future market conditions. *See also* 2010 IRP, Volume V, page S-3.

FIGURE 15: DETERMINISTIC PVRR FOR ALL PLANS IN 2010 IRP (2010–2029)

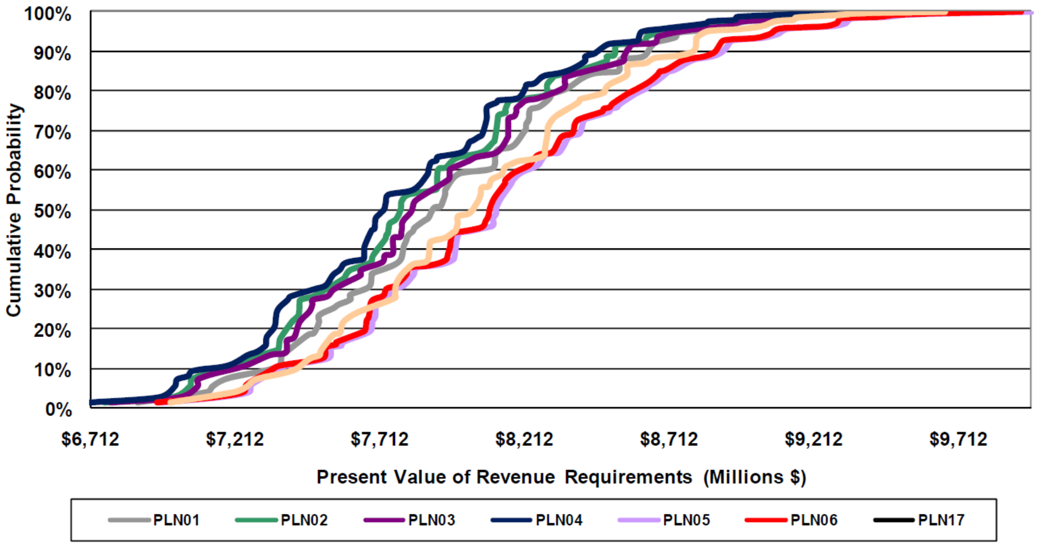


Source: 2010 IRP, Volume V, Figure 3-4.

Empire also tested the robustness of this preference for Plan 4 across a broad range of alternative risk scenarios reflecting uncertainty in environmental costs, market and fuel prices, load, capital and transmission costs, and interest rates.[34] The resulting risk profiles for the PVRR costs of Plans 1 – 6 (*i.e.*, the resource plans modeled under base assumptions) are shown in Figure 16 below, with that of the Plan 4 (in dark blue) seen consistently to the left of all the other curves, including that of Plan 6 which retired and replaced Asbury (in red). In fact, Plan 6 consistently ranks as nearly the most expensive alternative under most conditions. This demonstrates that Plan 4 was reliably the lowest risk and the cheapest strategy, about $200 – $300 million less costly than Plan 6.

[34] 2010 IRP, Volume I, pages ES-19 to ES-22; 2010 IRP, Volume V, pages 27 – 32.

FIGURE 16: RISK PROFILES OF ALL BASE SCENARIOS (2010–2029)



Source: 2010 IRP, Volume V, Figure 3-5.

Empire also conducted a 40-year break-even analysis in which it tested the sensitivity of its finding to the possible range of capital costs of the AQCS equipment. This study concluded that the AQCS retrofits would be more economical than the retirement option as long as the actual capital costs did not increase by more than $21 million beyond the initial estimate.[35]

In addition, Empire evaluated the break-even capital cost of the AQCS retrofits in 2011 as a result of newly decreasing expectations for future natural gas prices and changes in the outlook for allowance prices of GHG and SO_2/NO_x emissions that had occurred since its 2010 IRP analysis. The sensitivity results presented to Empire's Board of Directors in October 2011 concluded that the AQCS retrofits would continue to result in cost savings relative to the retirement option as long as the AQCS capital cost remain below $137 million.[36] The AQCS project was completed in late 2014 at an actual cost

[35] Ventyx, "Empire District Integrated Resource Plan," 2010, page 41.
[36] Strategic Projects Presentation to Empire Board of Directors, October 24, 2011, slide 12.

of $121 million, below the estimate in 2010 and below the break-even thresholds estimated in late 2011.[37]

Q. What were the key drivers of the cost savings expected from sustaining the plant with the AQCS rather than retiring Asbury?

A. Savings from continuing to operate Asbury in future years (*i.e.*, the AQCS option) relative to the retirement option depend largely on the relative magnitude of the following: i) future operating margins of the plant relative to SPP energy prices; ii) cost of replacing the capacity of Asbury with new resources at a future year when Empire would need new capacity to meet its resource adequacy requirements; and iii) future capital expenditures on the plant that would be avoided by the retirement of Asbury. The higher the future operating margins (greater profitability) for Asbury and the higher the cost of replacing its capacity, the higher would be the savings from the AQCS option. Conversely, the higher the future capital expenditures at the plant that could be avoided by retirement, the lower the savings would be from the AQCS option.

As of the 2010 IRP (when Empire evaluated the potential customer cost savings from the AQCS retrofits), Empire was projecting the Asbury operating margins and the replacement capacity costs to be sufficiently large to more than offset the capital expenditures that were required, making the retrofits superior to early retirement of Asbury.

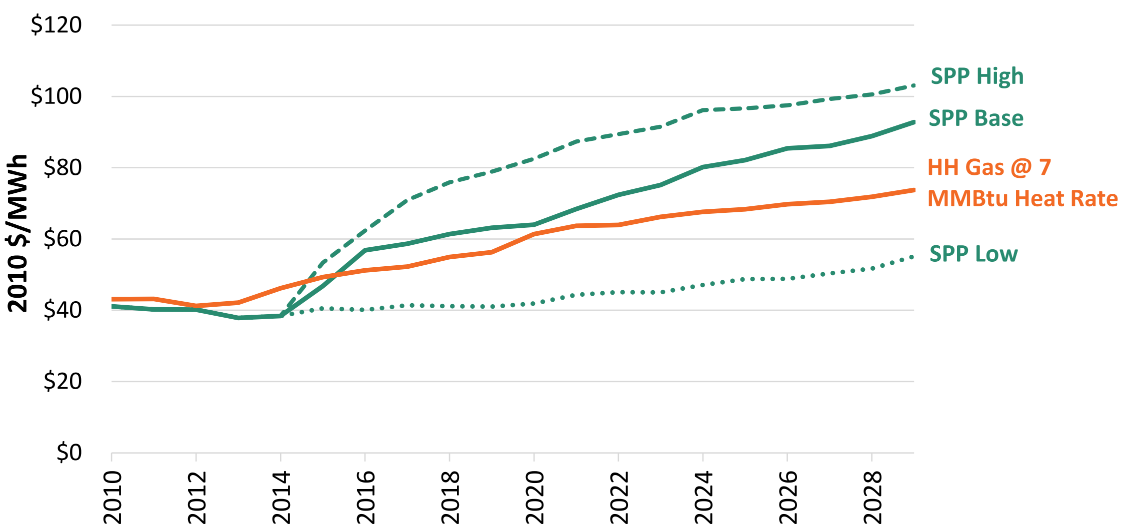
Future Operating Margins of Asbury

In most wholesale market regions, including SPP, operating margins of coal plants have been largely driven by natural gas prices since gas-fired units tend to be the marginal

[37] Empire District Electric Company. Asbury Asset Listing as of February 29, 2020. The AQCS project also included $21 million investment for a turbine upgrade.

units setting the wholesale energy prices. Therefore, one of the key drivers for the Asbury retirement economics is gas prices. Figure 17 shows Empire's outlook in the 2010 IRP for SPP wholesale energy prices (shown in green) and Henry Hub gas prices, expressed in terms of what they would cost for electricity at a new gas plant (shown in orange). The projected increase in gas prices, and the resulting increase in wholesale energy prices, were then expected to result in growing operating margins and high system benefits from Asbury in the future.

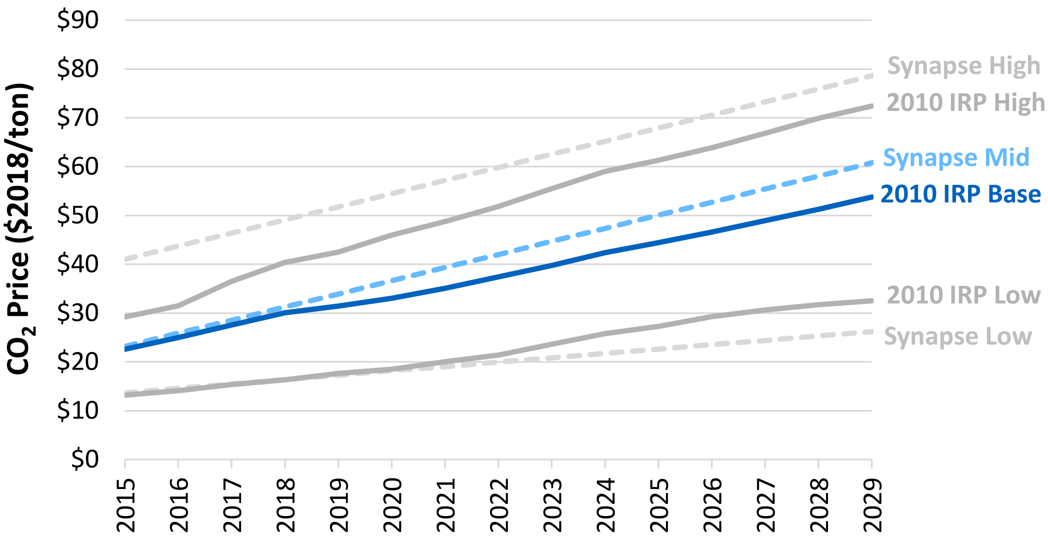
FIGURE 17: SPP ENERGY PRICE AND HENRY HUB GAS PRICE FORECASTS IN THE 2010 IRP



Source: 2010 IRP, Volume III, Figure 3-2 and Table 3-6.

In addition, the possibility of carbon emissions pricing in the future would impact the operating margins of coal plants through an increase in both coal fuel costs and wholesale energy prices. Gas plants would also face an increased cost, but because gas is often on the margin and is less carbon-intensive than coal, the net effect would be more adverse to the economics of the coal plant. The carbon prices Empire applied are shown in solid blue in Figure 18 below in comparison to the range of similar assumptions used by other utilities around the country at that time.

FIGURE 18: COMPARISON OF CARBON PRICE FORECASTS IN THE 2010 IRP



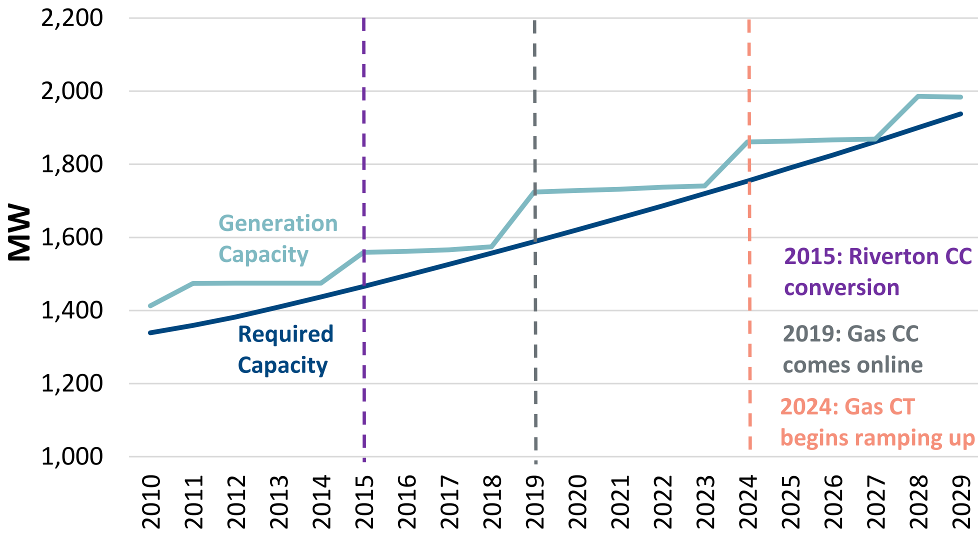
Source: 2010 IRP, Volume III, Table 3-9; David Schlissel *et al.*, "Synapse 2008 CO2 Price Forecasts," July 2008, Table 2, https://schlissel-technical.com/docs/reports_34.pdf.

The carbon prices applied by Empire are essentially centered in the industry range. These are non-trivial carbon prices, more than enough to have meaningful environmental impact on industry practices with regard to dispatch and development of new fossil fuel plants. Hence, they were a very legitimate test of the consequences of such pricing (which has not occurred, though most utilities continue to evaluate their fleet as if this will occur or as if they should choose the resources that would be best if it were to occur.)

Replacement Capacity Costs

Regarding the replacement capacity costs associated with the retirement of Asbury, the key factors are the timing of the need for Empire to replace Asbury's capacity with new resources and the projected cost of such new resources when they need to be installed. As of 2010, Empire was projecting significant future load growth such that the retirement of Asbury before its end of life would have required immediate replacement of that capacity with new resources. Figure 19 below shows that even with the continued operation of Asbury under the preferred resource Plan 4, Empire was projecting only a small, iteratively fleeting capacity surplus between its total generation capacity and the load requirements for its customers. That is, they were essentially in balance with the Preferred Plan, recognizing lead times and scale economies in power plant expansion.

FIGURE 19: CAPACITY BALANCE IN THE 2010 IRP PREFERRED PLAN (PLAN 4)



Sources and Notes: 2010 IRP, Volume V, Table B-1. Required capacity = (peak load with demand-side management) × (1 + 13.7% reserve margin).

With regard to costs, the next best alternative new generation to replace Asbury's capacity (a gas CC) was projected to cost about $720/kW, or over $140 million to build (in addition to having higher operating costs than the coal plant under then-prevailing gas price forecasts).[38]

Q. Have you evaluated the reasonableness of Empire's projections in those studies compared to the prevailing industry outlook at the time?

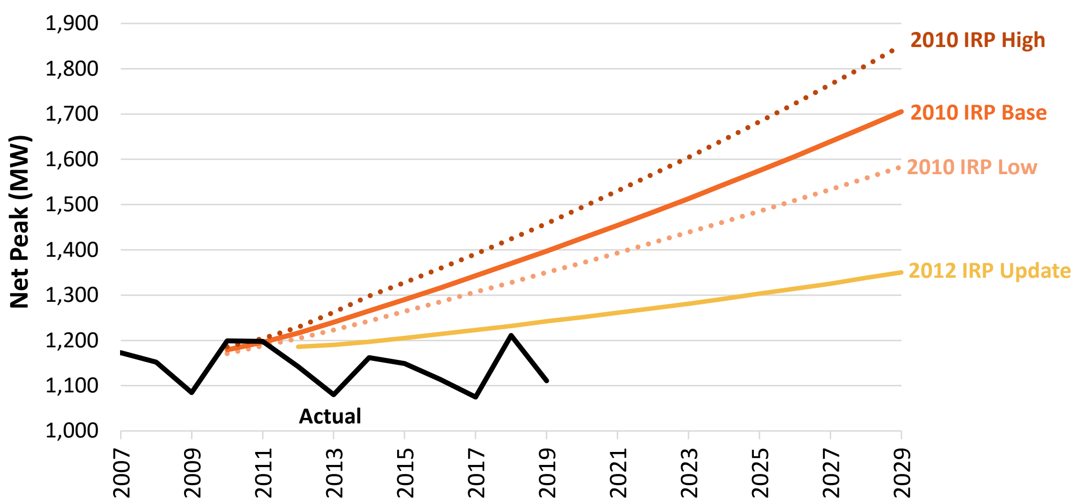
A. Yes, I have. Empire's long-term projections for future load growth, gas prices, and carbon prices were consistent with the prevailing industry outlook as of 2010.

[38] 2010 IRP, Volume III, Table 4-3. Assumes replacement of Asbury with a 200 MW gas CC.

Load Growth

The 2010 IRP projected peak load growth of 1.9% per year.[39] This was higher than the 1.3% compounded annual growth rate for peak load in SPP over the next 10 years forecasted by NERC's reliability assessment at the time.[40] However, the 2010 IRP also included a low peak demand forecast with an annual growth rate of 1.6% per year from 2010 – 2020 as a sensitivity to account for the uncertainty in load projections, shown in Figure 20 below.[41] Empire later revised its forecast downward in the 2012 IRP Update (shown in yellow), which projected a growth in peak load of 0.8% per year (about two and a half times lower than the 2010 base forecast).[42]

FIGURE 20: WINTER PEAK FORECASTS IN THE 2010 IRP AND 2012 IRP UPDATE



Source: 2010 IRP, Volume II, Table 2-11; 2012 IRP Annual Update, Table 4.

[39] Compounded annual growth rate from 2010 to 2020. *See* 2010 IRP, Volume II, Table 2-11.

[40] North American Electric Reliability Corporation, "2010 Long-Term Reliability Assessment," October 2010, page 158, https://www.nerc.com/files/2010_LTRA_v2-.pdf.

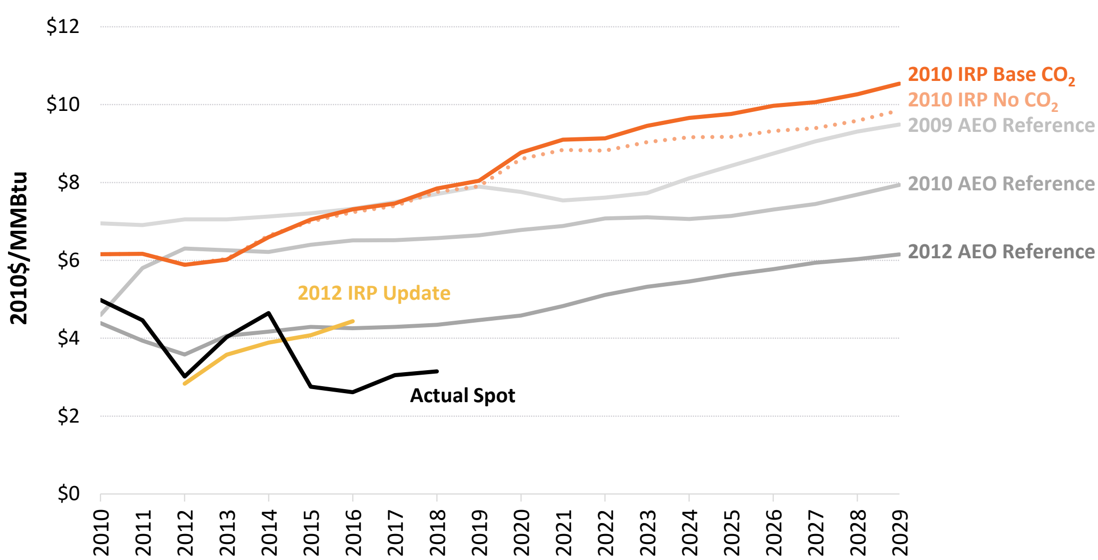
[41] 2010 IRP, Volume II, Table 2-11.

[42] Compounded annual growth rates from 2012 to 2029. *See* 2012 IRP Annual Update, Table 4.

Natural Gas Prices

Empire used natural gas price forecasts based on the ABB/Ventyx Fall 2009 Power Market Advisory Service Electricity & Fuel Price Outlook, with any carbon price expected to start in 2015. Figure 21 shows that these forecasts (in orange) were in the range of the 2009 AEO reference case Henry Hub price projections (in light grey). A revised forecast in the 2012 IRP update (shown in yellow) was somewhat lower than the 2012 AEO reference case (shown in dark grey) and actual realized Henry Hub spot prices (shown in black) were much lower than any of the projections. This decline in natural gas prices, shown through the progressively lower prices in the AEO projections, could not have been anticipated as the base or most likely condition at the time and, as explained earlier, is one of the reasons the operational economics at Asbury declined.

FIGURE 21: HENRY HUB GAS PRICE OUTLOOKS IN THE 2010 IRP AND 2012 IRP UPDATE



Sources and Notes: 2010 IRP, Volume III, Table 3-6; 2012 IRP Annual Update, Table 1; AEO 2009; AEO 2010; AEO 2012. The data in Table 1 of the 2012 IRP Update are NYMEX Henry Hub spot market prices plus a basis adjustment for the Southern Star Central Pipeline (where Empire takes delivery). The Southern Star prices are adjusted to Henry Hub prices using forwards as of January to March 2012 from S&P Global Market Intelligence. *See* 2012 IRP Annual Update, page 6.

Carbon Prices

As discussed above and shown in Figure 18, the CO_2 prices used in the 2010 IRP were within the range of industry expectations, with the base case forecast in the middle of the Synapse 2008 forecast (the most recently available at the time).[43]

Q. Did other coal plants in the U.S. also install pollution control equipment around 2015 to comply with the environmental regulations?

A. Yes. For example, Montrose units 2 and 3, and Sibley unit 3 in Missouri and Eckert Station units 4-6 in Michigan installed retrofits in 2015 and 2016 for reducing mercury emissions, but Montrose and Sibley retired later in 2018, while Eckert retired in 2020. Similarly, the North Valmy unit 1 in Nevada installed dry sorbent injection ("DSI") equipment at the end of 2014 for reducing SO_2 and acid gas emissions, but is now announced to retire in 2021. During the period 2014 – 2016, about 63 GW of coal capacity (209 units) in the U.S. installed environmental control equipment (12 GW from 38 units in the SPP region). Of these units, 9 GW (including Asbury) have already retired largely due to deteriorating outlook for market fundamentals, and 14 GW is announced to retire by 2030.[44]

Q. What are your conclusions with respect to the prudency of Empire's 2010-11 decision to invest in the AQCS?

A. Empire's projections as of 2010 for the key drivers of the potential cost savings from installing AQCS retrofits instead of retiring Asbury were reasonable and consistent with the contemporaneous industry outlook. In addition, Empire's evaluation in 2010

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43 David Schlissel *et al.*, "Synapse 2008 CO2 Price Forecasts," July 2008, Table 2, https://schlissel-technical.com/docs/reports_34.pdf.

44 Velocity Suite, ABB Inc., data as of February 18, 2021.

considered reasonable scenarios and sensitivities to evaluate the robustness of the projected cost savings with the AQCS option.

B. SCR Retrofit

Q. Please describe the industry outlook prior to 2008 for the key drivers affecting the economics of continued investments at existing coal plants?

A. Prior to 2008, the long-term gas price outlook in the energy sector generally favored continued investments at existing coal plants. In the 2007 Annual Energy Outlook, the EIA forecasted the natural gas price to reach $6.76/MMBtu in 2010 (2008 dollars) and $6.15/MMBtu by 2020. Similarly, in the 2007 IRP, Empire forecasted a gas price at $6.47/MMBtu (2008 dollars) in 2010, and escalating at 3% to reach $7.80/MMBtu by 2020, assuming that a carbon tax would begin in 2012.[45] These projected gas prices reflect a consistent assumption across most utilities in the U.S. that also drove widespread continued investments in coal fired plants. Indeed, after Hurricane Katrina in August 2005, there was general anxiety in the energy industry that our gas and oil infrastructure was fragile and insufficient, causing prices to rise rapidly and generally stay high until the financial crisis in collateralized lending caused the Great Recession starting around mid-2008. Even then, they did not drop to historic lows.

In addition, prior to 2008, customer load in the SPP region was expected to have substantial growth. In 2007, NERC's reliability assessment forecasted a 1.7% annual average load growth rate over the next 10 years in the SPP region, and Empire forecasted a 2.6% annual load growth rate within its footprint, indicating the expectation of a need

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[45] Gas forecast data taken from U.S. Energy Information Administration, "Lower 48 Wellhead and Henry Hub Spot Market Prices for Natural Gas, 1990-2030 (2005 dollars per thousand cubic feet)," February 2007. https://www.eia.gov/outlooks/archive/aeo07/gas.html, and 2007 IRP, Volume I, page 13.

to invest in economic and reliable power to its customers and satisfy Empire's planning reserve margin of 13.7%.[46]

Emissions allowance prices at the time also favored continued investments in control equipment at the time. Economic studies conducted by the EPA found the NO_x emissions allowance costs to be $1,603/ton in 2010 (or about $6/MWh for a coal plant without SCR controls), increasing to $1,973/ton in 2015. Empire similarly projected $1,622/ton in NOx emissions costs, increasing to $1,711/ton in 2015.[47] Generally, the industry anticipated high gas and NOx emissions allowance prices, which would favor investing in emissions control equipment in coal plants instead of either retiring the coal to be replaced by new gas units or not installing the emissions controls.

Q. Did other coal plant owners in the SPP region invest in SCR and other capital-intensive control equipment around 2008?

A. Yes. For example, Sibley unit 3 owned then by Kansas City Power and Light (now Evergy Missouri West) installed a selective catalytic reduction system in 2009, while Sibley units 1-2 installed selective non-catalytic reduction systems in 2008, yet all three units retired in 2018. Additionally, the Tecumseh Energy Center unit 7 of Westar Energy (now Evergy Kansas Central) installed a low NOx Burner with close-coupled over-fire air in 2008, but retired in 2018.[48]

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46 North American Electric Reliability Corporation, "2007 Long-Term Reliability Assessment, 2007-2016," October 2007, page 194, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/LTRA2007.pdf; 2007 IRP, Volume II, Table 2. 2007 IRP, Volume III, page 17.

47 Emission cost data taken from U.S. Environmental Protection Agency, "Regulatory Impact Analysis for the Final Clean Air Interstate Rule," March 2005, Table D-3, https://archive.epa.gov/airmarkets/programs/cair/web/pdf/finaltech08.pdf; and 2007 IRP, Volume III, Table ES-2. Numbers are reported in 2008 real dollars, assuming a 0.8 lbs/MMBtu uncontrolled NOx emissions rate and 10 MMBtu/MWh heat rate based on approximating historical Asbury operating data.

48 Velocity Suite, ABB Inc., data as of February 18, 2021.

VI. <u>REGULATORY STANDARDS AND CRITERIA FOR RECOVERY OF PRUDENTLY INCURRED PAST INVESTMENTS</u>

Q. What are the economic reasons for cost recovery of undepreciated assets that are not used to the end of their initially expected lifespans?

A. Longstanding and economically well-justified ratemaking principles and standards in the utility industry strongly indicate that all prudently undertaken investments should be fully recoverable from customers, even if the underlying assets should at some point prove less economic than was originally intended. This is particularly important in those instances where retiring those prudent investments is likely to produce net savings to customers (even after accounting for those customers paying for the retired investments) and where disallowing full recovery of those prudent investments would result in an unwarranted windfall to customers and penalize the utility and its investors.

Resources are chosen because they are expected to have the lowest costs, but seeking absolute confidence that such will occur under any and all future circumstances would be uneconomical for customers, if not impossible. In fact, prudent planning for resource development by utilities should entail the expectation that the chosen assets will mostly, *but not under all* circumstances, result in lowest cost for customers relative to other alternatives. That is, a prudent resource plan should, from the day it is planned and chosen, be understood to be partially exposed to other alternatives turning out to have lower costs in some (but less than the majority of) reasonably foreseeable planning scenarios. This is unavoidable because utility investments involve long-lived assets that will operate over a horizon that cannot possibly be precisely forecasted or controlled. It is also economically better that resources be chosen (as they were here) when they are expected to produce robust but not absolute cost savings or benefits. (Indeed, this is why risk analysis is done via scenarios in IRPs. Nothing is ever found or chosen because it is always going to be better than everything else no matter what could happen.)

As a consequence, from inception, prudently chosen investments will have a built-in modest risk of possible future disappointment – of becoming "out-of-the-money" sometime during their engineering lives. If not, uneconomic, overly risk-averse decisions would be made instead, causing expected savings to be lost – for example, by waiting too long or for too much certainty to build, or by the utility choosing resource options that have lower investment risk (such as only relying on purchased power) but higher expected costs to customers. For the same reason that a prudently chosen plant will face some downside risk at inception, it is also not good planning practice to abandon it abruptly if/when it first falls out-of-market because there will still be significant future uncertainty and a possibility that its attractiveness will improve, or that its replacement would be more economical if delayed a few years (while other technologies improve and become cheaper). Fixed costs of shutting down may also be substantial or accelerated in time, making it more economical to wait a while on abandoning a weak asset for the option value of possible better future circumstances.

Importantly, when a resource is chosen with strong expected benefits, it will usually have produced many years of net benefits even if it eventually falls short of the original hopes, should it become bested by some new technology or by a shift of market conditions towards circumstances that were originally seen as unlikely. When such occurs, the prudent decision for the utility is to acknowledge its previously attractive investment is no longer providing a benefit to its customers and to retire the investment. Reasonable ratemaking principles and standards that recognize and support such decision-making and allow the utility full recovery on and of the retired investment provide the proper balance between the rights of both the customers and the utility's investors. Denying full recovery, on the other hand, would result in giving utilities an unhelpful incentive to operate plants until they have recouped all of their investment, even though closing the plant would be more cost effective and save customers money.

Q. Unregulated firms face obsolescence risk for their assets, yet they have no recourse to sunk cost recovery. Please explain why their situation is different than that of a utility, and why full cost recovery is consistent with the regulatory obligation to serve and the cost-based pricing constraints under which a utility operates.

A. The obligation to serve under cost-based regulation means that regulated utilities are not like unregulated firms in a couple of meaningful ways. First, unregulated companies can choose when and which market to enter and exit, whereas utilities have the obligation to serve every customer within their service territory. That obligation also extends to making investments in a least-cost manner as agreed by regulatory review. In return, customers bear the full costs of those choices and enjoy their full benefits.

Second, for their products and services, unregulated companies can charge what the market will bear, and they can keep the benefits (extra profits) for themselves when they have in-the-money assets. Of course, if they fail to successfully commercialize a product, they have to bear the sunk costs, but that risk of loss is balanced by their opportunities for large unregulated profits in well-chosen market niches. In contrast, utilities do not have free rein when it comes to determining when and where to enter a market nor on what to charge for their services. Instead, the level of earnings is subject to review and approval by the regulators. If investments made by utilities result in unexpected gains, utilities do not get to keep the upside. Thus, utilities should not be assigned the downside losses when assets happen to lose their economic advantages, e.g. under a simple "used and useful" criterion. This practice would create a "heads I break even, tails I lose" set of outcomes, which *per se* deprives the utility of a balanced opportunity for expecting to earn its allowed cost of capital. In expectation, it could only earn somewhat less. Such built-in deprivation would harm its access to capital and undermine its ability to provide the requisite quality of service.

Q. Please describe the unintended adverse incentives that would arise from a regulatory policy disallowing full recovery of retired out-of-the-money assets that were prudently chosen.

A. Disallowing full recovery of retired out-of-the-money assets that were prudently chosen and approved sends the wrong signals to and creates perverse incentives for resource planners and investors. Such a disallowance means that prior regulatory approvals cannot be relied upon. Going forward, it creates the expectation that utility investments cannot be expected to recover a full return on and of their costs: they will break even if the assets remain attractive, but will lose part of their value under unfavorable market conditions. As a result, investors would hesitate to support the utility. Every prudent asset intrinsically includes some chance it will not fulfill its expected value benefits under every circumstance. In addition, disallowance in this case sets a "no good deed goes unpunished" precedent, where the utility saves customers money by retiring uneconomic assets but is penalized for doing so. Staying the course would then be preferable for the utility, even if it means that another option leads to a net savings for customers in the long run.

Q. Aren't utility equity investors compensated for the risk of possibly not having all their investment costs recovered? Isn't that what the cost of equity allowance is for?

A. No, while that argument is superficially appealing, it stems from a misunderstanding on several levels. According to that argument, anything that foreseeably could go wrong is already priced into the risk premium for equity. Therefore, equity prices already reflect such risks, and disallowance should be allowed to go forward without further compensating investors. But that is not entirely correct. Not every type of risk, even though it may be foreseen by investors as possible, is priced into the cost of equity. In particular, one-sided, asymmetric risks that involve sudden, large, uncontrollable, non-standard possibilities of loss (only, with no upside) are neither measured nor compensated in cost of equity allowances. In fact, Empire's allowed cost of equity does not compensate investors (at Empire, or Empire's shareholders) for the risk of not recovering prudently incurred but no longer used and useful costs.

Q. Please explain how asymmetric risks arise and why they differ from risks that are compensated in the cost of equity.

A. While it is generally understood and agreed upon in financial economics that investors in an efficient financial market (such as we have in the U.S.) are aware of essentially all material future risks, it is not the case that all those risks are recognized in the same way. Risks that involve sharing in the variability of the economy as a whole tend to be priced into the cost of capital, because they tend to be undiversifiable. Risks that are unique or "idiosyncratic" to just the firm or product in question (such as whether an invention will work, or a large contract will be executed) tend to be priced into the valuation of those companies via assumptions about what it will do to their expected cash flows, but not via an adjustment to their cost of capital. So, it is not correct to say that any risk that utility investors can imagine, such as plant disallowances if prematurely shutdown, has already been reflected in the cost of capital.

In fact, the capital asset pricing model ("CAPM") method of assessing the cost of equity starts with the presumption that only systematic risk is priced, and its statistical methods only measure the extent of co-variability of the proxy stocks with the market as a whole. Hence, those measurements cannot reflect idiosyncratic, asymmetric risks, and major disallowances for a utility are of that nature: that is, they involve only one-sided possibilities (all downside), they are unique to the circumstances of a particular utility, and they will have little or no correlation with the state of the market as a whole.

Second, because risks like disallowance affect forecasted cash flows, they also affect equity valuation. This means that if we calculate the cost of equity with the discounted cash flow ("DCF") method for a firm facing this problem, both its growth in expected dividends and its company valuation will reflect the problem, and will do so in a mostly offsetting way (as long as the growth forecast and price are contemporaneous). As a result, the DCF-measured return on equity also will not be greater for firms facing potential disallowances than for firms that are not.

Q. Can you provide some intuition for why an expected possible loss is not offset by an investor demand for more profits in the future?

A. The reason is that there is no mechanism to force that recovery. An example may help. Consider two very similar homes with similar valuations, but one suddenly becomes aware that it is in a region that is going to be close to a new airport. The value of the airport-exposed home will fall, but it will not thereafter be expected to appreciate at a higher rate than the other home, simply because it became aware of new risk. Both will grow at the rate of the overall housing stock. The airport house can only recover that lost value if the risk goes away. Similarly, the value of a stock will fall if it faces a downside risk like a catastrophic loss, but once that is reflected in its price, the stock will now appreciate just like a normal stock in its industry. More formally, the expected cash flows of the firm will fall, but the discount rate on its future will not increase. The stock simply drops in value to the point where the normal return is adequate for new buyers to want it and for old shareholders to retain it, notwithstanding their disappointment.

Q. Does the regulatory process of setting allowed returns somehow offset this problem?

A. No, the allowed cost of equity is normally assessed with the CAPM and DCF methods, which, as I described above, will not measure this kind of risk.[49] These methods estimate the expected rate of return on assets or businesses of equivalent risk. Utility ratemaking applies that to the book value of the rate base assets – hence there is no extra allowance of any kind for conditions where that rate base, initially recognized as prudent, might get reduced because of future conditions. If that kind of ratemaking were the plan, then the allowances based on the market cost of capital would not be enough.

Moreover, there would be a paradox that giving some extra allowance for potential disallowances would seem to give permission for any sized disallowance in the future – because notionally that right would have been paid for already. Clearly there is no combination of payments and future disallowances that would be fair compensation for operating under those policies, as the extra allowance would only be enough if there were years of collecting it as a premium and if the possible future disallowances were capped at amounts consistent with how the risk was initially

[49] Further, when cost of equity measurements rely on a proxy group, it is necessary that that group face the same risks as the utility of interest as a precondition for it even being relevant to ask whether a particular type of risk is priced or not. Since large write-offs are relatively rare, they are very unlikely to even be part of the comparison group's data.

predicted and priced. This also demonstrates why asymmetric risks are more like an insurance problem. That industry only covers a certain dollar amount of future risk for a certain, limited amount of time, where the risk arises under knowable circumstances familiar to the underwriter. When the risk is open-ended and non-standard, insurance is often not available or is incredibly expensive.

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

A. Yes. In all resource plans evaluated in Empire's 2019 IRP analyses, the undepreciated past investment costs at Asbury are assumed to be fully recovered from its customers in the future years. The depreciation period for that recovery is assumed to be slower in the Preferred Plan compared to Plan 1: depreciation period goes until 2048 in the Preferred Plan, versus until 2036 in Plan 1.[50] A tax markup of the equity component is needed for the amounts to be compensatory.

Q. What would be the result if customers did not continue to pay the pre-tax return on the retired investment?

A. If the customers' responsibilities for paying some or all of the pre-tax return on the retired investment were waived here, the customers would receive an unwarranted windfall that would have numerous inequitable and inefficient consequences. This is because in addition to already receiving the savings benefits from Empire's decision to retire Asbury, customers would be getting an unjustified "bonus" of being relieved of having to pay the cost incurred by Empire in creating the savings benefit for the

[50] 2019 IRP, Data Response 0017.

customers, *i.e.*, the cost to Empire of foregoing its remaining unrecovered investment in Asbury.

Utility regulators and courts have long concluded that a utility may include prudent investments no longer being used to provide service in its rate base as long as the regulator reasonably balances consumers' interest in fair rates against investors' interest in maintaining financial integrity. With the retirement and full-cost recovery of Asbury, the proper balancing of interests is achieved because customers receive substantial cost savings in rates even after them paying the remaining pre-tax return on the retired investment, whereby Empire recoups its remaining (prudent!) investment in Asbury. On the other hand, the balancing of interest test clearly fails if customers receive all of the cost savings relating to the retirement of Asbury and Empire is not allowed to recoup its remaining investment in Asbury – penalizing the act that resulted in finding and obtaining the savings that will be received by the customers.

There is no balancing of interest that would be achieved by "loss-sharing" when Asbury retires, since there was no gain-sharing while it operated and for many years reduced customers' costs relative to not having the plant. The regulatory bargain is that the utility receives only break-even cost recovery even when the asset is well "in-the-money" (as it was for many years in the past), so the utility should not receive a penalty if/when the plant becomes "out-of-the-money" for reasons that do not involve a finding of imprudence. This would be particularly inequitable and egregious when the utility has itself identified the opportunity for win-win savings.

With respect to Asbury, the unwarranted windfall to customers (and the unjustified penalty to shareholders) from avoiding to pay the entire return on (but continuing to pay only the return of) the current undepreciated value of the past investments at Asbury would be $116 million.[51] This is the present value of the annual returns that Empire would have earned on that past investment cost balance until year 2038 under the Preferred Plan of the 2019 IRP.

Denying a utility the ability to recover its remaining investment in a retired plant, where that retirement has been demonstrated to have significant future net benefits to its customers, results in poor regulatory policy with very adverse incentives and signaling to investors and lenders. Customers and their regulators should encourage and reward utilities for finding new opportunities to reduce future costs, even if that involves abandoning a previously serviceable and prudently incurred investment. In contrast, denying full recovery would likely give utilities an incentive to operate plants until they have recouped all of their investment even though closing the plant would save customers money.

Q. What have regulators in other jurisdictions determined is appropriate in situations where operationally viable assets turn out to be less useful than new alternatives?

A. There is no *per se* standard here, because there is always room for debate about how well vetted the original decisions were. However, in my review, I have found that other state regulatory commissions have generally allowed full recovery of prudently incurred past investment costs, including costs such as construction work in progress and those associated with unusable inventory, when economics and regulatory mandates have driven early plant retirements and where such recovery meets the balancing test of consumer and utility interests, where both parties benefit from the decision and where a different decision would result in customers receiving an unreasonable windfall and the

[51] 2019 IRP, Data Response 0016. Corresponds to the net present value of the return on rate base at the 6.71% discount rate used in the 2019 IRP. *See* 2019 IRP, Volume 6, page 6-18.

utility receiving what in essence is a penalty for making the prudent decision. This reflects fairness with the regulatory mandates and constraints the utility is operating under (as discussed above) as well as the important recognition that punitive treatment would have perverse incentives, discouraging utilities from looking for opportunities to keep looking for lower cost resources than they currently have. I have found that the commissions have approved different approaches to such full recovery mechanism, but they have respected the continuity of full cost recovery treatment for prudently expended programs and assets.

Q. Please describe the different approaches you have seen commonly approved in your review of other jurisdictions.

A. One commonly approved mechanism is to transfer the remaining net book value of the plant to a regulatory asset on the company's balance sheet. The regulatory asset is then allowed to be amortized over the remainder of the plant's life, ensuring a full return of and on invested capital. For example, in 2011, the Alabama Public Service Commission notably issued a *blanket order* to Alabama Power Company, allowing it to recover "unrecovered plant asset balance and the unrecovered cost associated with site removal and closure" through the establishment of regulatory assets.[52] This was to enable Alabama Power Company to respond responsibly to new environmental regulations, without worry that formerly established prudent investments would be disallowed. In essence, they recognized not only the fairness of this approach but the incentive benefits of making it possible for the utility to continue to seek cost savings without having to protect sunk costs. As another example, the Public Utilities Commission of Nevada

[52] Alabama Public Service Commission, Informal Docket No. U-5033, Order, September 7, 2011, pages 1-2, 7-8.

approved in 2014 for Nevada Power Company to recover the net book values of the retiring coal plants (Reid Gardner coal units 1-4 and the company's share of Navajo coal plant) through regulatory asset treatment. The early retirement of coal units were mandated by legislature in Senate Bill 123 to close at least 800 MW of coal-fired generation capacity and to replace them with renewable or non-coal conventional generation.[53]

In another approach, I have found that some commissions have allowed crediting of the remaining net book value of the retiring plant against accumulated depreciation. By reducing accumulated depreciation an amount equal to the net book value of the retiring asset, the company's total net book value of assets would remain the same after the retirement. The adjusted residual asset base continues to earn the utility cost of capital. This approach also ensures a full recovery of return of and on invested capital. As an example, this approach was proposed by the Indiana Michigan Power Company in its 2014 application related to the retirement of its uneconomic Tanners Creek Plant. The company was permitted to reduce its accumulated depreciation on other assets by the remaining net book value of the Tanners Creek Plant, specifically porting the reduced accumulated depreciation to the remaining life of its separate Rockport Unit 1.[54]

A number of states in recent years have also allowed securitization as a tool for utilities to manage past investment costs. In short, securitization displaces traditional rate base with a separate form of cost recovery via proceeds of dedicated bond issuance.

[53] Public Utilities Commission of Nevada, Docket Nos. 14-05003 and 14-06022, Order, October 28, 2014, pages 11, 15, and 21.
[54] Indiana Utility Regulatory Commission, Cause No. 44555, Order of the Commission, May 20, 2015, pages 5-6.

The bonds payments are recovered directly from customers through a non-bypassable customer charge. Because payments are guaranteed, the bond interest is much lower than the utility's return on investment. As a result, securitization enables the utility to recover the cost that has lower out-of-pocket cash costs to customers than continued recovery as if the affected assets were still in service and in rate base. The New Mexico Public Regulation Commission in April 2020 approved the Public Service Company of New Mexico's request to securitize up to $360 million of unrecovered investments for San Juan Generating Station.[55] Similarly, the Wisconsin Public Service Commission in November allowed Wisconsin Electric Power Company to issue bonds for $100 million of its investment in pollution controls at the Pleasant Prairie plant.[56]

I summarize other instances of commissions allowing full recovery associated with similar coal plants that have retired in Appendix A.

VII. CONCLUSIONS

Q. Please summarize your conclusions.

A. It is appropriate for Empire to fully recover its remaining undepreciated investment at Asbury because:

i) Empire's past major capital investments at Asbury were prudently chosen to save costs for Empire's customers and comply with environmental regulations,

ii) the retirement of Asbury was reasonable and consistent with the recent industry outlook of rapidly shifting key market fundamentals, and it is beneficial for

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[55] New Mexico Public Regulation Commission, Case No. 19-00018-UT, Recommended Decision on PNM's Request for Authority to Abandon its Interest in San Juan Units 1 and 4 and to Recover Non-Securitized Costs, February 21, 2020, pages 4, 34-35. *See also,* New Mexico Public Regulation Commission, Case No. 19-00018-UT, Final Order on Request of Public Service Company of New Mexico for Authority to Abandon its Interests in San Juan Generating Station Units 1 and 4 and to Recover Non-Securitized Costs, April 1, 2020, page 2.

[56] Public Service Commission of Wisconsin, Docket No. 6630-ET-101, Financing Order, November 17, 2020, pages 1-2, 55-56.

Empire's customers on a present value basis and annually for many years into the future, and

iii) several recent regulatory decisions in other jurisdictions support the reasonableness of Empire's request for full recovery of past investment costs associated with Asbury, having awarded full undepreciated cost recovery to similarly prudent prior investments that subsequently became uneconomical.

In order to maintain the financial health and credibility of the Company, it is important that Empire be allowed to receive a full return both on and of its invested capital, as well as any shutdown and transitional costs. This will protect the cash flow and balance sheet, and also assure investors and lenders that the Commission is fairly recognizing that (1) the past investment costs incurred at the plant were already thoroughly subjected to established processes for identifying prudent investment choices to meet mandated needs, and (2) it should be encouraging (rather than penalizing) utility decisions of this kind, where the retirement along with its proposed replacement solar and solar-plus-storage capacity will create lower going-forward costs for customers than would have otherwise been incurred with the continued operation of Asbury.

Because of these economic findings, and because of the norms of the traditional and well-justified regulatory compact between a utility, its Commission, and its customers, the proper treatment of Empire's undepreciated investments at the Asbury coal plant is to allow Empire to fully recover those past investment costs in retail rates.

Q. Please explain the main implications if Empire were not allowed to recover all its past investment costs at Asbury.

A. The Asbury plant was beneficial for many years, but market circumstances have turned against its previous advantages. The fact of the plant recently becoming uneconomical in no way implies it was imprudently sustained; Empire's planners could not have foreseen the pace and depth of the changes that have rendered the plant uneconomic, while what they did anticipate was normal and consistent with good industry practices. If Empire's investors are now not allowed to recover their costs, it would not only be irrationally punitive (for finding a better alternative that reduces customers' overall costs with the retirement and replacement of Asbury), but it could also make future capital attraction for the utility more difficult or more expensive—*i.e.*, undermining credit metrics and cash position, possibly requiring returns exceeding the utility's current costs of borrowing or issuing equity as investors wary of prior regulatory treatment seek to account for future disallowances risks. At the same time, it would create perverse incentives for the utility to seek inferior alternatives for its customers, but of lower risk for its investors.

Q. Does this conclude your Direct Testimony at this time?

A. Yes, it does.

VERIFICATION

I, Frank C. Graves, under penalty of perjury, on this 28th day of May, 2021, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Frank C. Graves

APPENDIX A: EXAMPLES OF HISTORICAL COST RECOVERY TREATMENT FOR COAL PLANT RETIREMENTS IN OTHER STATES

Decision Year	Utility	Plant	State	Docket	Recovery Allowed	Undepreciated Costs Allowed for Recovery
2009	Public Service Company of Colorado	Cameo 1 & 2 Arapahoe 3 & 4 Zuni 1 & 2	Colorado	09AL-299E	Regulatory asset to cover decommissioning costs as well as to capture difference between depreciation expense in rates and GAAP-required depreciation expense	$21 million (As of November 2015)[57]
2011	Portland General Electric Company	Boardman	Oregon	UE 215	Regulatory asset, including remaining book value	$14 million additional cost in 2011
2012	Idaho Power Company	Boardman	Idaho	IPC-E-11-18	Regulatory asset to track accelerated depreciation, new investment pollution controls, and net decommissioning costs	$54 million
2012	Georgia Power Company	Plant Branch Units 1 & 2 Environmental CWIP on Plant Branch Units 1 & 2	Georgia	34218	Regulatory asset, including remaining net book value and unused inventory	$24 million (End of 2014) $12 million (Beginning of 2014)
2012	Rocky Mountain Power	Carbon Plant	Idaho	PAC-E-12-08	Regulatory asset, including remaining net book value	$55 million
2013	Georgia Power Company	Hammond	Georgia	42310	Regulatory asset, including remaining net book value	$744 million
2014	Black Hills Power	Neil Simpson I, Osage, and Ben French	South Dakota	EL13-036	Regulatory asset, including remaining net book value	$15 million
2014	Wisconsin Public Service Corporation	Pulliam 5 & 6 Weston 1	Wisconsin	6690-UR-123	Defer and amortize remaining undepreciated value	$12 million

[57] Retirements occurred prior to November 2015. Regulatory assets values were taken from Hearing Exhibit 106, Proceeding No. 16A-0231E.

Decision Year	Utility	Plant	State	Docket	Recovery Allowed	Undepreciated Costs Allowed for Recovery
2014	Nevada Power	Reid Gardner Units 1-3 Reid Gardner Unit 4 Navajo Generating Station	Nevada	14-05003	Regulatory asset, including remaining net book value	$135 million (2014) $113 million (2017)[58] $29 million (2019)
2014	Wisconsin Power and Light	Nelson Dewey 1 and 2 Edgewater 3	Wisconsin	6680-UR-119	Regulatory asset, including remaining book value.	$84 million (Nelson 1 - 2) $28 million (Edgewater 3)
2015	Public Service Company of New Mexico	San Juan Generating Station Units 2 & 3	New Mexico	13-00390-UT	Based on stipulation between utility, agency staff, and some intervenors, regulatory asset for 50% of remaining undepreciated value. No prudency issue found.	$116 million (half of the $231 million remaining value)[59]
2015	Kentucky Power Company	Big Sandy Units 1 & 2	Kentucky	2014-00396	Regulatory asset, including coal-related retirement costs of both units	$135 million
2016	Gulf Power Company	Plant Smith Units 1 & 2	Florida	160039-EI	Regulatory asset, including remaining plant balance and remaining inventory balance	$63 million
2016	Otter Tail Power Company	Hoot Lake	Minnesota	E-107/ D-19-547	Regulatory asset, including net book value	$7 million
2017	Idaho Power	North Valmy	Idaho	IPC-E-16-24	Regulatory asset to recover remaining plant balance in three years following retirement	$57 million
2017	Florida Power & Light Company	St. Johns River Power Park	Florida	20170123-EI	Regulatory assets to recover shutdown payment to joint owner, transfer of assets to joint owner, and remaining net book value of plant as well as remaining inventory balance	$282 million
2018	MDU Resources Group Inc.	RM Heskett Generating Station	North Dakota	PU-19-317	Regulatory asset, including remaining book value	$55 million
2018	Consumers Energy	D.E. Karn	Michigan	U-20165	Securitization, including remaining book value (pursuant to settlement agreement)	$779 million

58 Includes $33.8 million that is common across Units 1 – 4.

59 After $26 million of net book value was transferred to Unit 4 for the additional capacity.

Decision Year	Utility	Plant	State	Docket	Recovery Allowed	Undepreciated Costs Allowed for Recovery
2018	AEP Texas Inc.	Oklaunion	Texas		Regulatory asset, including remaining book value	$49 million
2018	Evergy Kansas Central Inc.	Tecumseh Energy Center	Kansas	18-WSEE-328-RTS	Regulatory asset, including remaining net book value for inclusion in future rate case	$28 million (as of 2010)[60]
2018	Public Service Company of Colorado	Comanche	Colorado	C18-0761	Regulatory asset, including remaining book value, through end of 2022 and 2025	$125 million for unit 1, $101 million for unit 2
2018	Allete Inc.	Clay Boswell	Minnesota	E-015/ GR-16-664	Regulatory asset, including remaining book value, depreciate through 2022	$43 million
2018	Wisconsin Electric Company	Pleasant Prairie	Wisconsin	6630-ET-101 & 05-UR-109	Pursuant to settlement agreement, partial securitization, including remaining net book value; remaining investment fully recovered	$100 million securitized $300 million fully recovered
2018	Wisconsin Power and Light	Edgewater 4	Wisconsin	6680-UR-121	Regulatory asset, including remaining book value	$57 million
2019	Evergy Missouri West Inc.	Sibley	Missouri	EC-2019-0200	Regulatory asset, including all costs and accumulated costs associated with the unit	$146 million
2019	Wisconsin Electric Power Company	Presque Isle	Wisconsin	167 FERC ¶ 61,175	Regulatory asset, including remaining book value	$183 million
2019	Alabama Power Company	Gorgas 8-10	Alabama		Regulatory asset, including remaining book value, to be recovered over units' remaining useful lives	$740 million[61]
2019	Dominion Energy Virginia	Chesterfield 3 and 4	Virginia	PUR-2018-00195	Regulatory asset, including remaining book value and most environmental projects. Disallowance of wet-to-dry ash conversion costs, "the Commission finds that Dominion has not established that the 'cost incurred' for this project was reasonable and prudent at the time such cost was incurred".[62]	$90 million[63]

60 Book value as of 2010.
61 Obtained from Southern Company, Form 10-K for the Fiscal Year Ended December 31, 2018, pages II-38, II-83, and II-293.
62 See *In Re Application of Virginia Electric Power Co.*, Docket No. PUR-2018-00195, Final Order, August 5, 2019, page 8.
63 Value for Chesterfield Power Station, which includes units 5 & 6 that are still in service.

Decision Year	Utility	Plant	State	Docket	Recovery Allowed	Undepreciated Costs Allowed for Recovery
2019	MDU Resources Group Inc.	Lewis & Clark	North Dakota/ South Dakota	PU-19-317/ EL19-040	Allowed to defer costs related to retirement for accounting treatment.	$32 million/ $4.8 million
2020	Duke Energy Progress	Asheville	North Carolina	E-2, SUB 1131	Regulatory asset, including remaining net book value, except for some of the coal ash recovery costs	$232 million
2020	Duke Energy Indiana	Gibson Station	Indiana	45253	Regulatory asset, including remaining book value, including coal ash costs	$212 million
2020	Public Service Company of New Mexico	San Juan	New Mexico	19-00018-UT	Securitization as requested by utility, including remaining net book value	$360 million