The Empire District Electric Company
Kansas Corporation Commission
Docket No. 18-EPDE-184-PRE
Response to Staff's Eighth Set of Data Requests

Response provided by: James McMahon

Title: Vice President, Energy Practice

Company Response Number: STAFF 8-73

Date of Response: March 1, 2018

Question:
Regarding the annual revenue requirement results from the original GFSA for Plan 2 Base and Plan 4 Base with Asbury:

a) The annual Plan 4 cost exceeds the Plan 2 cost by $53 million in 2036, rising to a difference of $70 million in 2047. Please provide a narrative description that explains the cost difference, in particular why costs are greater after Asbury has retired given that as of 2036 both Plans reflect 800 MW of Wind Projects and the absence of Asbury. Stated alternatively, why does delayed retirement of Asbury cause more than $700 million in excess costs from 2036 through 2047?

Response:
Please see the response, starting on page 6, in the attached memo, "Attachment STAFF 8-73_CRA_Memo_Updated Run Results_2018_01_21_.docx," for an explanation of the updated Plan 4 and costs erroneously associated with the original Plan 4. Please also see the results of the updated Plan 4b in the attached file, "Attachment STAFF 8-73 Additional GFSA Scenarios Results_Update_2_8.xlsx," in the "Plan 4 Sensitivities" tabs.

Memorandum

To: The Empire District Electric Company

From: James McMahon, Vice-President, Charles River Associates

Date: 1/21/2018

Subject: Updated Analysis Results

The Empire District Electric Company, following the submission of the Generator Fleet Savings Analysis (GFSA), performed several additional analyses to evaluate the impact of different assumptions on the nine plans established in the GFSA and to assess the performance of alternative potential plans. The different analyses are summarized below. Overall, the results of these analyses re-affirm the conclusion in the GFSA that adding 800 MW of wind to the portfolio will provide savings versus the plan identified in the 2016 IRP.

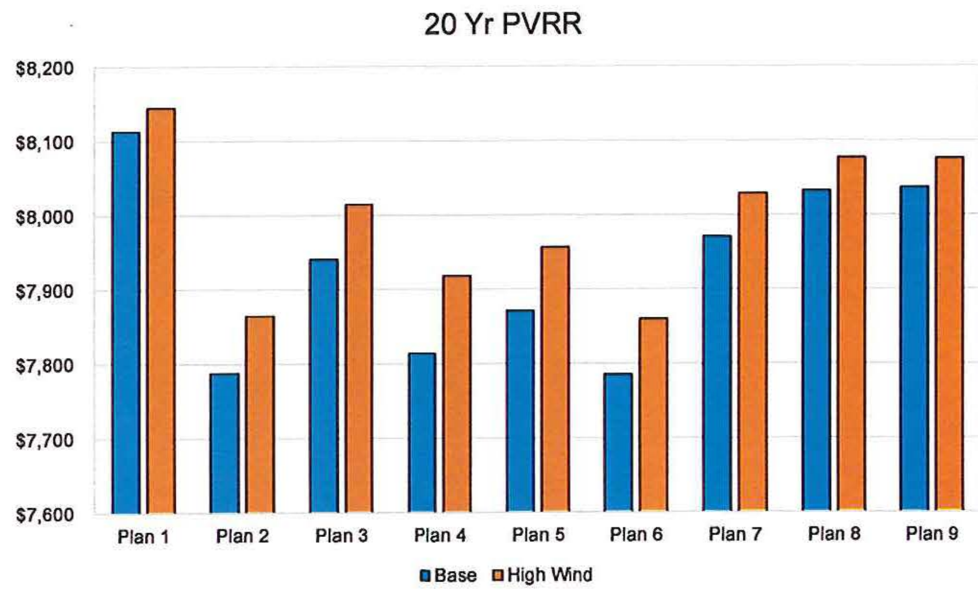
Additional Stakeholder Analysis, prepared January 2018

Analysis	New External Assumptions?	New Plans?	Comments
Alternative Assumption: High Wind, Less Coal	Yes, market price	No	Plans 1-9 evaluated against different SPP market outlook
Alternative Assumption: 40-yr Time Horizon	Yes, time horizon	No	Plans 1-9, with Base Case analysis time frame extended by 10 years
Alternative Assumption: Corporate Tax Change	Yes, tax policy	No	Plans 1-9 evaluated under original Base Case, but with new tax assumptions
Alternative Assumption: Load uncertainty – integrated into stochastics	Yes, load uncertainty	No	Plans 1-9, evaluated with a new critical uncertain factor (load) in addition to original set of three; new stochastic analysis with 54 total endpoints
Additional Plans: additional constraints and specific forced portfolio changes	No	Yes	8 new plans developed ("Plans 10-17"), run against the original Base Case
Additional Plans: optimized for DSM scenarios	No	Yes	4 new plans developed ("Plans 18-21"), run against the original Base Case

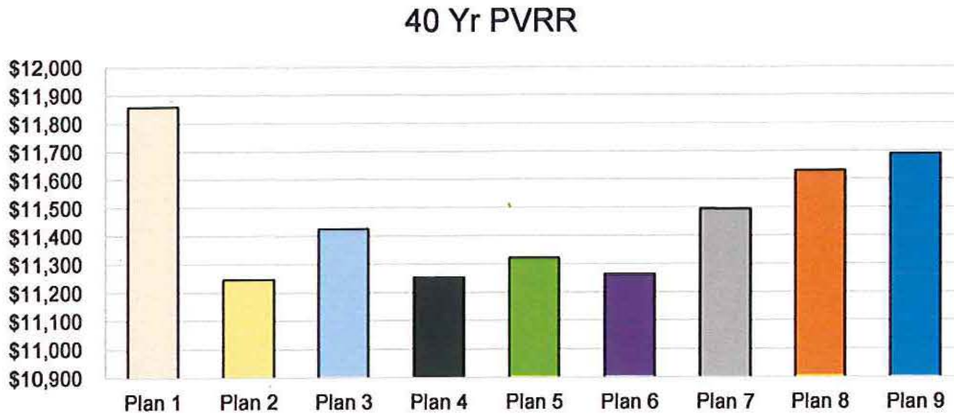
The accompanying file, "Attachment Additional GFSA Scenarios Results.xlsx" contains the details of the results for the various analyses. The primary findings are summarized as follows:

- *Alternative Assumption with high wind and less coal* – All nine plans were evaluated with an updated SPP market price forecast. The updated high wind case adds an additional 9 GW of wind to SPP over the forecast period and retires an additional 1.8 GW of coal in

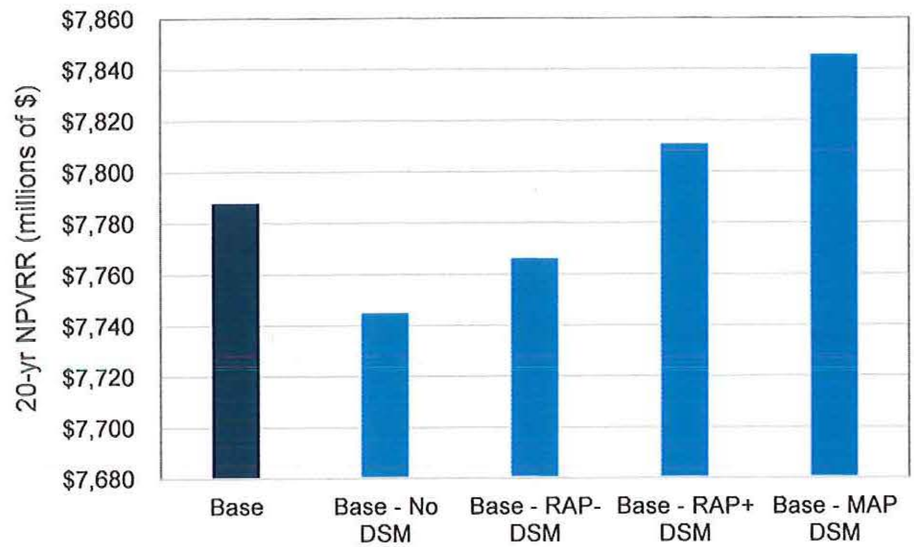
SPP. This resulted in a decrease in the market price of ~5-7% in the later years. The high wind / low coal pricing scenario resulted in increased costs for all plans, because Empire is expected to generate more electricity than native load in all cases. The plan most impacted was Plan 4 (retaining Asbury with 800 MW of wind), given that it has the highest generation. Plan 2 with 800 MW of wind was also affected more than the plans with lower amounts of wind, but still had the lowest cost overall. This is shown below for the 20-year NPVRR. The 30-year outlook is similar.



- *Alternative Assumption with 40-year time horizon* – The nine original plans were evaluated over a 40-year time period in addition to the original 20-year and 30-year frameworks. In extending the period to 40 years, additional natural gas capacity was added in each plan after the wind projects came offline or as reserve margin requirements demanded. Although Plan 2 requires additional capital expenditures versus Plan 1 at the end of the 40-year time horizon to replace the retiring 800 MW wind capacity, the additional costs do not meaningfully impact the PVRR. Overall, the 40-year study confirms the same plan ordering as was shown in the 30-year study, which is summarized below.

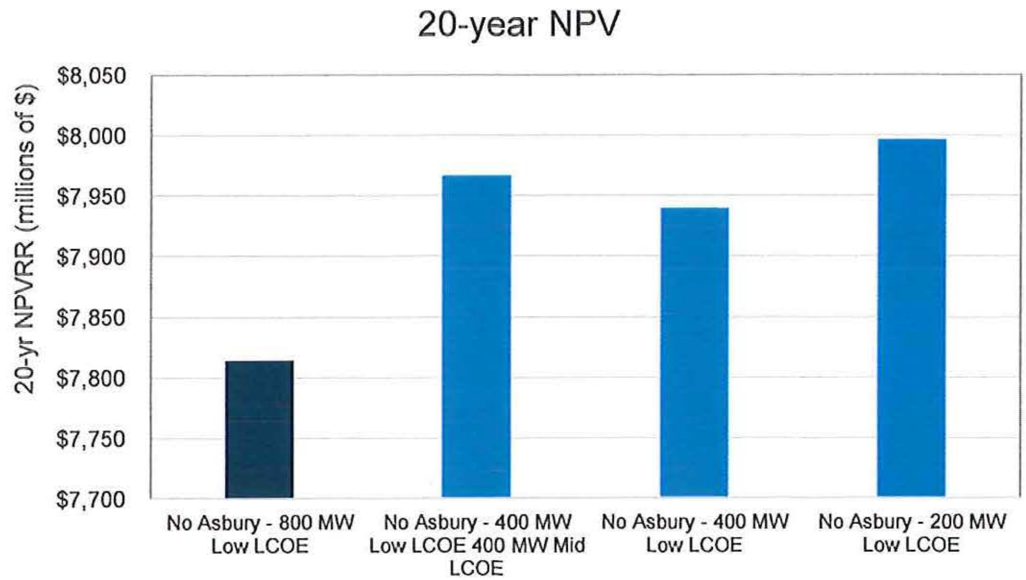


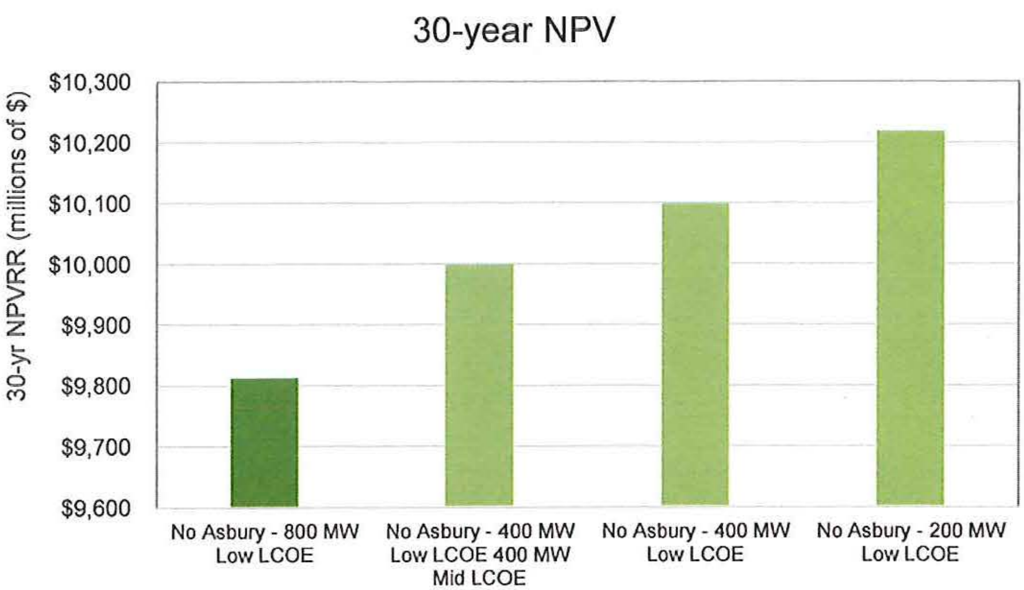
- *Additional Plans with Different DSM Assumptions* – Updated DSM plans were developed and evaluated against Plan 2 from the GFSA. Plan 2 from the GFSA included RAP DSM. The new plans were developed with No DSM, RAP-, RAP+ and MAP. In all four alternate DSM plans, 800 MW of Low-LCOE wind was still built, as in Plan 2 (the Base Plan). The new plans resulted in slight changes in new build timing. Adding more DSM increased the relative cost of Plan 2 by up to $58M on a 20-year NPV basis (vs. MAP). Removing DSM decreased the relative cost of Plan 2 by up to $43M on a 20-year NPV basis (No DSM). These results are shown below, with the relationship the same on the 30-year NPV basis.



- *Additional Plans with New Constraints* – The plans with additional constraints either adjusted Plan 2 (800 MW of low-LCOE wind) or Plan 4 (keep Asbury with 800 MW of low-LCOE wind).

- Additional wind constraints were placed on Plan 2 from the GFSA, to limit the new wind quantities to 400 MW and 200 MW versus the original 800 MW built in Plan 2 in the GFSA.
  - The plan with a 400MW limit resulted in an incremental cost of $167M over 20 years
  - The plan with a 200MW limit resulted in an incremental cost of $243M over 20 years
- Wind constraints were also placed on Plan 4, limiting the amount of Low-LCOE wind to 400 MW, limiting Low-LCOE wind to 400 MW and Mid-LCOE wind to 0 MW, and limiting Low-LCOE wind to 200 MW and Mid-LCOE wind to 0 MW.
  - The plan with a 400 MW limit on Low-LCOE wind resulted in an incremental cost of $153M on a 20-year basis and $186M on a 30-year basis
  - The plan with a 400 MW limit on Low-LCOE wind and 0 MW limit on Mid-LCOE wind resulted in an incremental cost of $125M on a 20-year basis and $287M on a 30-year basis
  - The plan with a 200 MW limit on Low-LCOE wind and 0 MW limit on Mid-LCOE wind resulted in an incremental cost of $182M on a 20-year basis and $406M on a 30-year basis
  - It should be noted that the relative cost impacts varied across plans for the 20-year and 30-year time horizon, as the performance of mid-LCOE improves over time as market prices are expected to increase. This is shown below.





- Other constraints placed on Plan 4 included delaying the Energy Center retirement, replacing the 167 MW reciprocating engine with a gas CT, and replacing the 167 MW reciprocating engine with a gas CT as well as removing the solar builds.
    - The plan that delays the retirement of Energy Center reduces costs by $4 million on both a 20-year and 30-year NPV basis.
    - The plan that replaces the reciprocating engine with a CT increases costs by $11 million (20-year NPV) and $36 million (30-year NPV).

    - The plan that replaces the reciprocating engine with a CT *and* removes solar increases costs by $5 million (20-year NPV) and $48 million (30-year NPV).

- *Alternative Assumption with Corporate Tax Change* – The nine original plans were evaluated with revised assumptions regarding the corporate tax rate, as per the federal tax reform legislation passed in December, 2017. The tax reform update resulted in a decrease in the PVRR for all nine plans from the GFSA, by ~$300-400M, depending on the plan. The savings from Plan 2 relative to Plan 1 increased from $325M to $340M (20-year NPV). The savings from Plan 3 relative to Plan 1 increased from $172M to $261M (20-year NPV). The updated tax reform scenario resulted in an increase in capital cost for both Low-LCOE and Mid-LCOE wind, due to a slight decline in the value of tax equity financing. The capital cost for Low-LCOE wind (assuming 100% PTC) increased from $671/kW to $768/kW, and the capital cost for Mid-LCOE wind (assuming 100% PTC) increased from $769/kW to $864/kW. As demonstrated by the increase in savings in Plans 2 and 3, all Plans with new wind continue to demonstrate significant savings versus the 2016 IRP plan, despite the slight increase in effective capital costs. Other major changes to the modeling include an updated corporate tax rate to 21%, which decreases the revenue requirement for Empire in all cases and an update to the accumulated deferred income tax liability associated with the Asbury early retirement.
- *Alternative Assumption with Load Uncertainty* – The nine original plans were evaluated against an additional critical uncertain factor for Empire load growth. Two new load growth trajectories expanded the stochastic analysis from 18 endpoints to 54 endpoints. The high load growth case assumed the 2016 IRP high load case, while the low load growth case assumed the 2016 IRP low load case, less 3.5% to adjust for demand side reductions less an assumed amount of new community solar. In general, the high load cases tend to *increase* the PVRR relative to the base load cases, and the low load cases tend to *decrease* the PVRR relative to the base load cases. The savings for Plan 2 relative to Plan 1, however, largely do not change across the base, high, and low load cases. This is because the various resources in each plan still generate the same in the SPP market regardless of Empire's native load. The details of these results are shown in the "Attachment_54 Endpoint Stochastic Income Statements_Final.xlsb" fie.

Updated Plan 4

A new plan, labeled 4b in the accompanying spreadsheet, was added to the portfolio to reflect a correction to Plan 4. Plan 4 erroneously included approximately $65 million of additional annual costs associated with a reciprocating engine generation resource after it was added in 2035. The impact of this change is a PVRR that is $49 million lower than Plan 4 on a 20-year basis. This change has not impacted the forecasted economics of the wind additions contained in the plans.

Plan 4b performs relatively better over the long-term versus Plan 2 after the reciprocating engine accounting correction because of the rising gas prices in the base case. Plan 2 builds 200 MW of combined cycle capacity in the mid-2020s that Plan 4b does not build, as a result of Asbury remaining in service. Plan 4b instead builds 200 MW of solar in the early 2030s and 167 MW of reciprocating engine capacity in 2035. As gas prices rise, the solar units perform relatively better than the combined cycles, improving Plan 4b's relative performance over time.

Across the stochastic analysis, Plan 2 results in lower costs than Plan 4b across most of the endpoints. This is because it performs better most of the time when CO2 prices are in place and all of the time when market prices are low. In the 20-year NPV analysis, Plan 2 is lower cost than Plan 4b in 12 of the original 18 endpoints (or 36 of the new 54 endpoints), with an expected value that is $41 million lower in the full stochastic analysis update ("summarized in Attachment_54 Endpoint Stochastic Income Statements_Final.xlsb"). In the 30-year NPV analysis, Plan 2 is lower cost than Plan 4b in 11 of the original 18 endpoints (or 33 of the new 54 endpoints), with an expected value that is $18 million lower in the full stochastic analysis update. Relative to Plan 4, Plan 2 provides risk mitigation against a potential market outcome with more sustained low gas prices, and hence low SPP market prices, and under most market outcomes when a carbon price is in place.