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Case No.: EA-2025-0299  
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**Before the Public Service Commission  
of the State of Missouri**

**Surrebuttal Testimony**

**of**

**Aaron J. Doll**

**on behalf of**

**The Empire District Electric Company d/b/a Liberty**

**May 27, 2026**



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THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY  
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION  
CASE NO. EA-2025-0299

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SURREBUTTAL TESTIMONY OF AARON J. DOLL  
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1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Aaron J. Doll. My business address is 602 South Joplin Avenue, Joplin,  
4 Missouri.

5 **Q. Are you the same Aaron J. Doll who provided direct testimony in this matter on**  
6 **behalf of The Empire District Electric Company d/b/a Liberty (“Liberty” or the**  
7 **“Company”)?**

8 A. Yes.

9 **Q. What is the purpose of your surrebuttal testimony in this proceeding?**

10 A. I respond to criticisms raised by Missouri Public Service Commission Staff (“Staff”)  
11 Witness Hari Poudel regarding Liberty’s economic analysis in the 2025 Integrated  
12 Resource Plan (“IRP”). Specifically, I will clarify the record regarding how the  
13 Levelized Cost of Energy (“LCOE”) was utilized in our planning process, and I will  
14 detail the advanced economic modeling frameworks that actually drive the selection of  
15 our Preferred Plan and the F-Class combustion turbine. I will also address concerns  
16 raised by Staff regarding the assumptions used in the IRP. Specifically, I will address  
17 the winter Planning Reserve Margin (“PRM”) forecasts and the accredited capacity  
18 assumptions used by the Company during the development of its 2025 triennial IRP.  
19 I will respond to Staff’s criticism regarding the Company’s selection of an F-Class  
20 turbine rather than a J-Class turbine, specifically as it relates to the planning aspect of  
21 resource development. Additionally, I will address the Company’s positions on various

1 Staff conditions. I will also address Renew Missouri’s concerns relating to the  
2 evaluation of DSM, solar and battery energy storage system (“BESS”) in the  
3 Company’s IRP and Preferred Plan selection. Additionally, I will respond to OPC  
4 witness Dr. Marke’s concern about the Company’s capacity need and whether this  
5 resource was studied to support a data center. Finally, I will also address Dr. Marke’s  
6 mischaracterization of a news article in the Joplin Globe regarding whether the  
7 Company intends to seek Construction Work In Progress (“CWIP”) treatment and how  
8 that was communicated in the article.

9 **II. LCOE DISCUSSION**

10 **Q. Please summarize Staff Witness Poudel’s criticism regarding the Company’s use**  
11 **of LCOE as an economic analysis tool in the Company’s 2025 IRP?**

12 A. Staff Witness Poudel criticizes the use of LCOE as an economic analysis tool to justify  
13 the selection of generation resources. Relying on reports from the National Renewable  
14 Energy Laboratory (“NREL”) and the Electric Power Research Institute (“EPRI”), Mr.  
15 Poudel asserts that LCOE is an incomplete metric that fails to capture the technologies  
16 full economic value to the system. Consequently, he suggests that these metrics are not  
17 reliable for utility generation cost comparison purposes, implying that Liberty’s  
18 selection of the ~250 MW F-Class turbine over other alternatives was based on a flawed  
19 economic screening tool.

20 **Q. Does Liberty agree with Mr. Poudel’s assertion that LCOE has limitations as an**  
21 **ultimate decision-making tool?**

22 A. No. However, Liberty agrees with the fundamental premise that LCOE, when used in  
23 isolation, has limitations. As the EPRI report cited by Staff correctly notes, LCOE  
24 makes no pretense of measuring total system value, system costs, or the relative

1 economic competitiveness of different resources operating within a dynamic energy  
2 market. However, Staff has fundamentally mischaracterized how Liberty utilized  
3 LCOE in its 2025 IRP. To be clear for the record, Liberty did not use LCOE as the  
4 ultimate economic justification for selecting the Preferred Plan or the F-Class  
5 combustion turbine.

6 **Q. If LCOE was not the ultimate economic justification, how was it utilized in**  
7 **Liberty's 2025 IRP?**

8 A. LCOE was strictly used as a preliminary, high-level screening mechanism to comply  
9 with explicit requirements of the Commission's IRP rules. Under 20 CSR 4240-  
10 22.040(2)(A), utilities are legally required to provide cost rankings of each potential  
11 supply-side resources option based on "estimates of the installed capacity costs plus  
12 fixed and variable operation and maintenance costs levelized over the useful life of the  
13 potential supply side resource option using the utility discount rate."

14 **Q. How did this preliminary screening fit into Liberty's broader analysis?**

15 A. The Company approached resource evaluation in stages. First, we started with a broad  
16 list of all potential resource types, including emerging technologies like hydrogen,  
17 small modular nuclear reactors, and various storage durations, and subjected them to a  
18 technical feasibility screen. Second, we applied the LCOE and Levelized Cost of  
19 Capacity ("LCOC") screens mandated by the Commission to eliminate options that  
20 were entirely commercially unviable or excessively costly relative to other resources.  
21 The important takeaway here is that almost all technically feasible generation  
22 technologies, including renewables, storage, and multiple classes of gas turbines  
23 (including the F-Class), successfully passed this preliminary LCOE screen. They were  
24 then advanced to the shortlist of candidate resources for the actual rigorous economic

1 integration analysis. LCOE was a screening tool used to comply with an IRP rule  
2 requirement, it did not dictate the final resource selection.

3 **Q. What was the actual economic analysis tool used to select the F-Class turbine and**  
4 **Preferred Plan 4?**

5 A. The actual economic justification for the F-class turbine was determined through the  
6 Capacity Expansion Modeling (“CEM”), specifically using the Aurora model,  
7 combined with an extensive Net Present Value of Revenue Requirement (“NPVRR”)  
8 risk analysis.

9 Once the candidate resources passed the initial screening, they were entered  
10 into Aurora to develop and evaluate alternative resource plans. The core of the Aurora  
11 model is an hourly, chronological dispatch algorithm that simulates the actual  
12 operations of the Southwest Power Pool (“SPP”) Integrated Marketplace (“IM”).  
13 Aurora does exactly what LCOE cannot do; it minimizes total portfolio costs while  
14 simultaneously adhering to complex operating constraints, unit commitment  
15 conditions, transmission limits, etc. across every hour of the year.

16 **Q. How did Aurora modeling and NPVRR calculations lead to the selection of**  
17 **Preferred Plan 4?**

18 A. Aurora evaluated 12 distinct alternative resource plans, optimizing the additions of  
19 supply-side and demand-side resources over a 20-year and 30-year planning horizon.  
20 The Company tested the resilience of each alternative plan against 81 different  
21 subjective probability endpoints based on Critical Uncertain Factors (“CUFs”). These  
22 CUFs included variables such as future load growth trajectories, carbon/emission  
23 prices, natural gas price volatility, and capital cost of new builds. The Company  
24 calculated the NPVRR of each plan on an expected value basis across all 81 risk

1 scenarios to determine which portfolio provided the best balance of cost and risk  
2 migration.

3 Plan 4, which centers on the 240 MW F-class frame combustion turbine  
4 additional alongside renewable and demand-side resources, was selected because it  
5 produced the lowest NPRVV over both the 20-year and 30-year horizons. It was the  
6 most cost-effective and risk-resilient portfolio evaluated under a highly rigorous  
7 stochastic analysis.

8 **Q. Staff cited reports from NREL and EPRI in support of concerns regarding**  
9 **Liberty’s methodology. Do those reports conflict with the approach taken by**  
10 **Liberty?**

11 A. Not at all. In fact, a careful reading of the NREL and EPRI reports cited by Staff shows  
12 that those institutions champion the exact methodology that Liberty utilized in its IRP.  
13 The EPRI report cautions that while LCOE is a convenient summary statistic, “it is well  
14 known that actual decisionmakers use more complete and analytically rigorous  
15 modeling frameworks for energy resource decisions.”<sup>1</sup> Liberty did exactly that by  
16 utilizing the Aurora CEM and Strategic Energy Risk Valuation Model (“SERVM”) for  
17 the Company’s resource decisions.

18 Similarly, the NREL report criticizes simple LCOE metrics because they fail to  
19 capture the technologies “full economic value to the system” such as capacity value  
20 and ancillary services. Crucially, the NREL report concludes that “Optimization-based  
21 capacity expansion models (“CEMs”) are particularly well-suited to quantify  
22 competitiveness metrics because they consider both fixed and operating  
23 costs...intrinsicly reflect the long-run system needs and conditions...and

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<sup>1</sup> <https://esca.epri.com/pdf/Back-Pocket-Insights/EPRI-P201-LCOE-Brief.pdf>

1 endogenously reflect the competition between technologies and their interactions with  
2 grid requirements to estimate service price and provision.”<sup>2</sup>

3 **Q. How does Liberty’s use of the Aurora model address the “system value” concerns**  
4 **raised in the NREL report?**

5 A. NREL defines an asset’s “system value” as being derived from the suite of services it  
6 provides to the interconnected grid, specifically: energy value, capacity value, and  
7 ancillary services. Because Aurora performs an hourly unit commit and dispatch  
8 simulation for the SPP IM, it dynamically calculates the exact system value  
9 components NREL identifies.

10 Aurora evaluates how a resource like the F-Class combustion turbine performs  
11 during critical peak hours, how it contributes to SPP’s tightening accredited capacity  
12 (“ACAP”) and winter planning reserve margins, and how it interacts with intermittent  
13 renewable resources in the portfolio. This optimization-based capacity expansion  
14 modeling captures the full economic value of the resources, moving far beyond the  
15 static limitations of an LCOE calculation.

16 **Q. What is your conclusion regarding Staff’s concerns about the Company’s use of**  
17 **LCOE as an economic analysis tool in the IRP?**

18 A. I respectfully submit that Staff’s criticism is based on a misunderstanding of how the  
19 analysis is structured. Staff has conflated a preliminary, legally mandated screening  
20 step (LCOE) with the final economic decision-making framework. Liberty did not  
21 select the F-Class turbine based on LCOE. Liberty utilized CEM (Aurora) across  
22 thousands of hours of chronological SPP market dispatch and rigorous stochastic  
23 analysis. This methodology is fully aligned with the NREL and EPRI guidance cited

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<sup>2</sup> <https://docs.nrel.gov/docs/fy21osti/72549.pdf>

1 by Staff, and it comprehensively demonstrates that Plan 4 was properly selected as the  
2 least-cost, least-risk option for customers.

3 **III. 2025 IRP MODELING ASSUMPTIONS**

4 **Q. What is the purpose of this section of your surrebuttal testimony?**

5 A. The purpose of this section is to respond to certain concerns raised by Staff Witness  
6 Trevor Rucker regarding the Company's 2025 IRP modeling assumptions.  
7 Specifically, Mr. Rucker asserts that the Company relied on inaccurate assumptions by  
8 modeling a 44% Winter PRM for the 2029/2030 winter season and by not applying the  
9 2025 SPP conventional resource class-average accreditation values to the proposed  
10 project.

11 As explained below, those conclusions are not supported when the timing and  
12 sequence of the IRP modeling process are considered. Staff's analysis relies on  
13 information that became available only *after* key modeling assumptions had to be  
14 established, locked, incorporated into a complex portfolio modeling process. The  
15 Company's assumptions were not inaccurate when made. They reflected the best  
16 available SPP guidance, the then-current resource adequacy information, and a prudent  
17 approach to planning in a rapidly tightening capacity environment.

18 **Q. Does the Company agree with Mr. Rucker's assertion that Liberty relied on**  
19 **inaccurate assumptions?**

20 A. No. The Company respectfully disagrees. Mr. Rucker's conclusion evaluates the  
21 Company's IRP modeling using final or later-developed SPP information that was not  
22 available, finalized or approved during the critical period in which Liberty and its  
23 consultant, Charles River Associates ("CRA"), were finalizing the portfolio setup and  
24 modeling assumptions. The Company did not use "inaccurate" assumptions; rather, the

1 Company used the best, most up-to-date information and official guidance available  
2 from SPP at the time the modeling decisions had to be locked in. Only after the IRP  
3 was advancing through the rigorous portfolio modeling phases did SPP update  
4 information that changed some of those preliminary assumptions.

5 **Q. Please summarize Staff Witness Rucker’s concern regarding the Company’s 2029**  
6 **Winter PRM assumption and the Company’s response.**

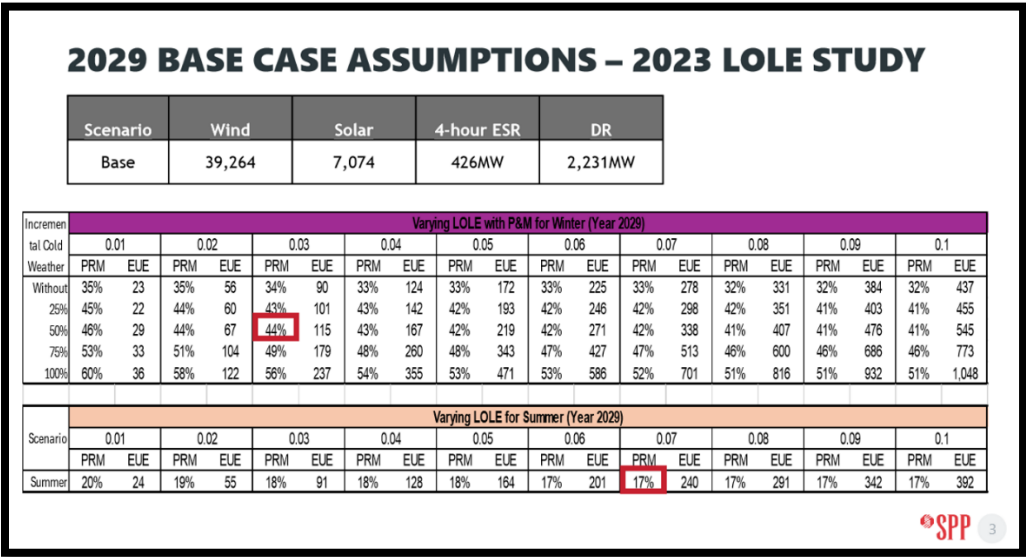
7 A. Mr. Rucker questions the Company’s use of a 44% Winter PRM for the 2029/2030  
8 winter season. He notes that SPP ultimately established a lower 38% Winter PRM for  
9 that period and suggests that the Company’s modeling may have overstated its future  
10 capacity need. The difficulty with that position is that it evaluates the Company’s  
11 modeling against a final outcome that was not formally established during the relevant  
12 modeling window.

13 **Q. Why did the Company assume a 44% Winter PRM for 2029 in its IRP modeling?**

14 A. The Company did not create the 44% figure independently. That figure reflected SPP  
15 guidance available during the core IRP modeling period. SPP’s 2023 Loss of Load  
16 Expectation (“LOLE”) Report, which served as the foundation for the 2029 PRM  
17 analysis, was published in June 2024. Following that report, SPP materials presented  
18 the 2029 base PRM as 44% for the winter season and 17% for the summer season  
19 during the period in which the Company and CRA were developing the IRP modeling  
20 framework. See Figure AJD-1 below for the presentation made to the Resource Energy  
21 and Adequacy Leadership (“REAL”) team on July 8, 2024.

1

Figure AJD-1



2

3 **Q. When did SPP change its guidance from 44% to 38% for the 2029 Winter PRM?**

4 A. SPP did not issue a recommendation to reduce the 2029 Winter PRM to 38% until  
 5 September 17, 2024. It is important to note, the SPP Regional State Committee  
 6 (“RSC”) did not formally endorse the lower 38% PRM until February 3, 2025, which  
 7 was several months after Liberty’s modeling assumptions had to be finalized.

8 **Q. If SPP Staff or working groups began discussing a lower 2029 PRM in September  
 9 2024, why did the Company not immediately adjust its modeling assumption?**

10 A. Preliminary SPP Staff or working group discussions are not the same as final SPP  
 11 approval. SPP’s stakeholder process is complex, and recommendations can change as  
 12 they move through the Supply Adequacy Working Group (“SAWG”), the Market  
 13 Operational Policy Committee (“MOPC”), the Member’s Committee (“MC”), the  
 14 RSC, and the SPP Board of Directors (“BOD”).

15 The risk is asymmetric. If the Company plans a lower PRM that is later rejected  
 16 in favor of a higher requirement (e.g. plans for 38% while 44% is ultimately  
 17 implemented), the Company could be left with insufficient accredited capacity and

1 limited time to cure the deficiency. By contrast, planning to the more conservative  
2 requirement reflected in the then-current SPP guidance better protects customers from  
3 reliability, compliance, and market exposure.

4 **Q. Please provide a recent example demonstrating the risk of treating preliminary**  
5 **SPP recommendations, particularly a lowering of reserve margins, as final.**

6 A. SPP's approval of Revision Request 622 ("RR622") illustrates this risk precisely.  
7 During the summer of 2024, there was substantial debate regarding the appropriate  
8 winter PRM. The SAWG approved a 33% winter base PRM, and the MOPC likewise  
9 recommended that the SPP BOD approve the 33% winter PRM. The MC also voted  
10 against a proposal to approve a 36% winter PRM on August 6, 2024. In other words,  
11 multiple member represented working groups either supported the lower 33% winter  
12 PRM or opposed a counter-proposal 36% winter PRM.

13 **Q. What did the SPP BOD and RSC ultimately decide?**

14 A. Despite the lower 33% recommendations by the technical working groups within the  
15 stakeholder process, the RSC and SPP BOD ultimately approved the higher 36%  
16 Winter PRM.

17 That recent history is important because it demonstrates that working group and  
18 stakeholder recommendations do not control the final outcome. The RSC and SPP  
19 BOD may, and recently did, adopt a more conservative reliability requirement than the  
20 level supported earlier in the stakeholder process.

21 **Q. How does that recent history inform Liberty's decision to maintain the 44%**  
22 **Winter PRM assumption in its IRP modeling?**

23 A. It confirms that Liberty's approach was reasonable given the timeline and the dynamic  
24 environment within which the Company was operating at the time. At the time the

1 Company was finalizing its IRP assumptions, SPP had already demonstrated through  
2 RR622 that final PRM decisions could move in a more conservative direction than  
3 preliminary stakeholder recommendations. Given that context, it was reasonable not  
4 to emergently try to incorporate a lower winter PRM merely because lower values  
5 began to emerge in preliminary working group discussions.

6 Liberty was planning in a resource adequacy environment where the  
7 consequences of underestimating capacity are significant. A shortfall of accredited  
8 capacity can expose customers to reliability risk, deficiency costs, limited bilateral  
9 capacity options, and compressed development timelines. The Company therefore  
10 continued with the assumptions developed during the modeling process; and what  
11 resulted was not an overstatement of need, but rather a prudent planning response to a  
12 changing and increasingly stringent SPP resource adequacy construct.

13 **IV. ACCREDITED CAPACITY (“ACAP”) PRM**

14 **Q. What is an ACAP PRM?**

15 A. Accredited Capacity Planning (“ACAP”) Planning Reserve Margin (“PRM” or “RM”),  
16 is the reserve margin or the amount of additional capacity needed beyond expected  
17 peak load conditions, after resources are adjusted to reflect the capacity SPP expects  
18 them to reliably contribute during the applicable season. Prior to SPP developing  
19 Performance Based Accreditation (“PBA”) standards for thermal generation, the SPP  
20 Planning Criteria utilized Installed Capacity (“ICAP”) which is nearly synonymous  
21 with nameplate. The ICAP figure had to be proved through operational testing on a  
22 regular cadence to establish an accredited capacity figure. However, after the Improved  
23 Resource Availability Task Force (“IRATF”) recommended that SPP transition to a  
24 historical performance-based standard for accredited capacity determinations, the SPP

1 working group process proposed and approved a PBA standard for thermal resources,  
 2 to go along with an Effective Load Carrying Capability (“ELCC”) standard for non-  
 3 traditional resources. The result of these changes was for SPP to determine a Base  
 4 PRM utilizing the annual Loss of Load Expectation (“LOLE”) study, then convert that  
 5 Base PRM into a Minimum Required Accredited Capacity (“MRAC”) figure utilizing  
 6 decremented capacity and then converting that MRAC into a percentage for the purpose  
 7 of creating an ACAP. Figure AJD-2 is an example from the SPP Planning Criteria of  
 8 the conversion process from Base PRM to ACAP PRM.

**Figure AJD-2**

Variable	Value	Formula
Summation of LRE Peak Demand	50,000	[A]
Base PRM	15%	[B]
Minimum Required Capacity (Base PRM)	57,500	$[C] = [A] + [A]*[B]$
Summation of Conventional Resources Demonstrated Net Generating Capability	60,000	[D]
Summation of Conventional Resources Accredited Capacity	57,000	[E]
Difference in Conventional Resources Capacity	3,000	$[F] = [D] - [E]$
Minimum Required Accredited Capacity	54,500	$[G] = [C] - [F]$
Accredited Capacity PRM	9%	$[H] = ([G]-[A]) / [A]$

*Table 4.1: Is used for reference purposes only and does not always reflect the latest PRM.*

10  
 11 **Q. What is Staff’s position regarding the Company’s planning assumption for the**  
 12 **ACAP PRM?**

13 A. Staff Witness Rucker asserts that the Company should have applied SPP’s 2025  
 14 conventional class-average accreditation values to the proposed 250 MW F-Class  
 15 combustion turbine. Mr. Rucker contends that applying those class averages would  
 16 have produced lower initial accredited capacity values than those reflected in the  
 17 Company’s IRP modeling.

1 Again, the issue is not whether different values became available later. The issue is  
2 whether those values were available in time to be incorporated into the IRP modeling  
3 process in a reasonable, supportable, and technically coherent manner.

4 **Q. How did the Company and CRA develop ACAP assumptions in the absence of**  
5 **final SPP 2025 class-average values?**

6 A. CRA developed a forward-looking accreditation forecast using the best information  
7 available at the time. The Company and CRA did review the SPP conventional  
8 resource class-average values after they were published; however, those values did not  
9 eliminate the need for a forecast. They represented point-in-time class-average  
10 reference, not a complete set of future-year accreditation values for the IRP planning  
11 horizon.

12 The distinction is important. The Company was not only modeling the 2025  
13 planning years. It was developing a long-term resource plan that required assumptions  
14 regarding how the proposed resource would be accredited in future periods, including  
15 the 2029 timeframe. The published class-average values did not provide sufficient  
16 underlying detail to determine reliable trends or to isolate how much of the  
17 accreditation adjustment was attributable to ordinary forced outage performance,  
18 incremental winter or fuel-related outage risk, changes in the reference case capacity  
19 mix, or other evolving components of SPP's performance based accreditation  
20 methodology.

21 Accordingly, CRA could not simply apply the 2025 class-average values  
22 mechanically across the IRP planning horizon. CRA used those values as a reference  
23 point, along with the available SPP methodology and guidance, but still had to apply  
24 professional judgment and simplifying assumptions to develop forward-looking ACAP

1 values. Staff's comparison to the 2025 class averages may be useful as a retrospective  
2 benchmark, but it does not demonstrate that the forward-looking assumptions were  
3 unreasonable.

4 **Q. What is your conclusion regarding Staff's concerns about the Company's**  
5 **modeling assumptions?**

6 A. Staff's concerns are understandable when viewed with the benefit of later SPP  
7 decisions and publications, but they should not be viewed as supporting evidence that  
8 the Company's assumptions were unreasonable when made. The Company did not rely  
9 on unsupported or arbitrary assumptions. It relied on then-current SPP guidance, the  
10 June 2023 LOLE information, and a conservative planning approach in a tightening  
11 SPP resource adequacy environment. The fact that SPP later revised, finalized, or  
12 created different resource adequacy inputs does not undermine Liberty's modeling. If  
13 anything, it underscores the volatility and uncertainty of SPP's evolving resource  
14 adequacy framework and supports the Company's decision to plan with a reasonable  
15 amount of conservatism for dispatchable winter capacity.

16 **V. TURBINE SELECTION – IRP**

17 **Q. Summarize Staff's critique of the Company's decision to select the approximately**  
18 **250 MW F-Class combustion turbine.**

19 A. Staff Witnesses Hari Pouel and Trevor Rucker note that in the Company's Technology  
20 Assessment Study, the Company evaluated a 420 MW J-Class simple cycle combustion  
21 turbine. Staff points out that the turbine was modeled as \$200/kW less expensive than  
22 the F-Class turbine on an installed capacity basis. Staff further notes that their analysis  
23 indicates a single J-Class turbine could satisfy the Company's summer capacity needs  
24 through 2044 and the Company's winter capacity needs through 2039/2040.

1           Consequently, Staff questions why Liberty selected the F-Class option and whether the  
2           Company properly evaluated the benefits of the larger J-Class unit against potential  
3           transmission upgrade costs.

4   **Q.   On page 28 of their Rebuttal Report, Staff references the Company’s response to**  
5   **Data Request 83 and Data Request 69 to assert that the Company “did not select**  
6   **the least-cost alternative” because it chose the F-Class turbine over the larger J-**  
7   **Class turbine. Is Staff’s conclusion correct?**

8   A.   No, Staff’s conclusion relies on an apparent misunderstanding of how least-cost  
9        planning is performed. Staff apparently bases its argument entirely on the fact that the  
10       J-Class turbine has a lower installed capacity cost on a strictly \$/kW basis. However,  
11       selecting a generation resource based solely on the lowest \$/kW metric is not least-cost  
12       planning. Staff has provided no evidence or portfolio modeling to demonstrate that  
13       selecting the J-Class would lower the total cost of service to Liberty’s customers.

14   **Q.   Does the Company dispute Staff’s assertion that the J-Class has a lower \$/kW**  
15   **cost?**

16   A.   No, we do not dispute the math of the \$/kW metric. However, Staff’s reliance on the  
17       \$/kW metric ignores the practical realities of the total capacity expenditure required  
18       and the actual timing of our customers’ capacity needs. While the J-Class turbine is  
19       estimated to cost approximately \$200/kW less than the F-Class, it has a nameplate of  
20       420 MW, which is 75% larger than the 250 MW F-Class. Purchasing the oversized  
21       unit would drive an estimated 60% increase in total upfront project costs. To utilize  
22       the J-Class, Liberty would be forced to install roughly 170 MW of excess capacity five  
23       years ahead of the schedule outlined in the Company’s 2025 IRP Preferred Plan.

1 **Q. Did the Company consider transmission upgrade risks when evaluating the J-**  
2 **Class option?**

3 A. Yes, transmission upgrade risk was a major factor in our decision. Our Site Selection  
4 Study explicitly indicated that injecting more than 308 MW of new capacity at the State  
5 Line site could trigger substantial transmission network upgrade risks and significant  
6 cost exposure.

7 Because a J-Class turbine exceeds that 308 MW threshold, pursuing it would  
8 have introduced cost and schedule uncertainties into the project. Staff admits in their  
9 report that they cannot determine the full extent of the transmission upgrades, and  
10 associated costs, that would have been required for a J-Class turbine. It is not prudent  
11 planning to commit our customers to a 60% higher capital cost while simultaneously  
12 exposing them to unknown, potentially fatal transmission upgrade liabilities.

13 **Q. How did the SPP Expedited Resource Adequacy Study (“ERAS”) process impact**  
14 **your technology selection?**

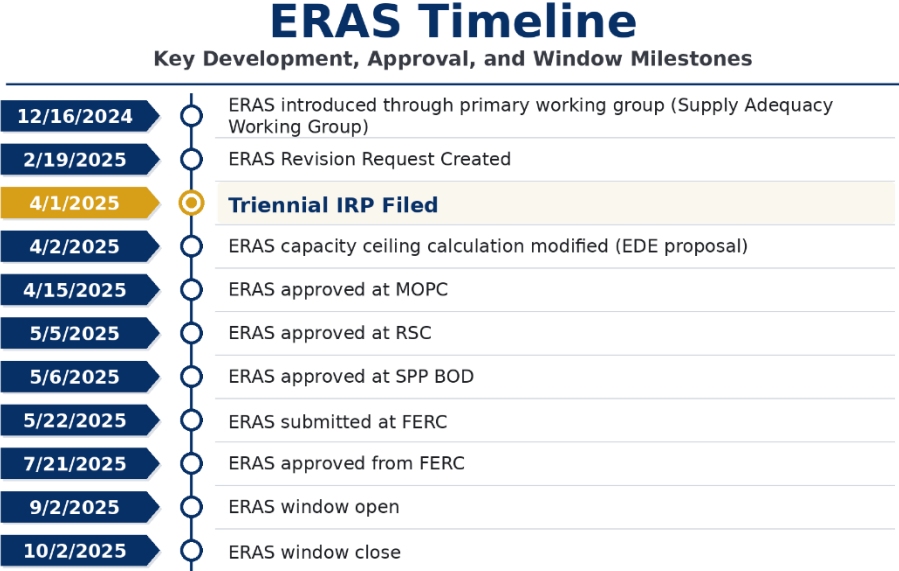
15 A. The ERAS process was the only viable pathway available to accelerate the  
16 interconnection of new generation to meet our 2029/2030 resource adequacy  
17 obligations. Because the transmission risks identified with larger injections, Liberty  
18 submitted its ERAS application for 250 MW to minimize the likelihood of triggering  
19 substantial network upgrades.

20 **Q. Explain the timeline associated with the ERAS process and how it impacted the**  
21 **Company’s ability to interconnect new generation.**

22 A. See Figure AJD-3 below for a brief description of the relevant ERAS timelines relevant  
23 to the Company’s processes.

1

Figure AJD-3



2

3

The ERAS process was a one-time, highly compressed study process created by SPP to accelerate the addition of new generating resources to the grid. As the timeline above illustrates, the ERAS framework was created and developed concurrently with the Company’s 2025 Triennial IRP. SPP’s BOD did not approve ERAS until May 6, 2025, and FERC did not issue its final approval until July 21, 2025.

8

Following FERC approval, the ERAS process provided a very narrow framework for the Company to secure a path to meet its 2029/2030 resource adequacy obligation. The Company had to rapidly finalize its capacity requirements, site selection, technology parameters, and submit its application with enough time to cure any deficiencies before the ERAS window closed and the cure period terminated.

13

The ERAS timeline, combined with the risk of triggering transmission network upgrades that jeopardized cost and timelines, contributed to the ruling out of the larger J-Class turbine.

14

15

1 **Q. Staff notes that their analysis indicates the single J-Class turbine could satisfy the**  
2 **Company's summer capacity needs through 2044. Is there risk with locking in**  
3 **that level of capacity today?**

4 A. Yes. The analysis assumes our capacity needs will remain static for the next twenty  
5 years. In reality, the Company's capacity needs and the SPP RA construct evolves  
6 rapidly. Locking in a large 420 MW J-Class turbine today to satisfy a projected need  
7 in 2035 or 2044 strips the Company of the flexibility to adapt to future market  
8 conditions or technological advancements.

9 **Q. Can you provide a recent example of how rapidly the Company's capacity needs**  
10 **can evolve?**

11 A. Yes, the drastic shift between our 2022 IRP and our 2025 IRP is a perfect example. In  
12 our 2022 IRP, our system was primarily constrained in the summer season.  
13 Consequently, our preferred plan at the time relied heavily on adding utility-scale solar  
14 and storage to meet our obligations. However, by the 2025 IRP, SPP had implemented  
15 major reforms as discussed in my direct testimony. These changes migrated our  
16 capacity need from a summer-constrained season reliant on solar, to a winter-  
17 constrained season heavily reliant on dispatchable, winter-accredited combustion  
18 turbines. If the Company had early adopted capacity based on the assumptions from  
19 the 2022 IRP, we would not have been positioned to pivot effectively to the new winter  
20 mandates.

21 **Q. Are there specific assumptions in the current 2025 IRP that could change and**  
22 **negate the need for the excess capacity a J-Class turbine would provide?**

23 A. Yes. The projected long-term capacity need that Staff suggests a J-Class turbine could  
24 satisfy is premised, in large part, on the planned retirement of Energy Center Units 1

1 and 2 in 2035. While retirement of those units is currently assumed in our Preferred  
2 Plan, it is entirely possible that future analysis will justify pushing those retirements  
3 further out.

4 **Q. Is there a precedent for delaying the retirement of Energy Center 1 and 2?**

5 A. Yes. In the 2019 IRP (EO-2021-0331), the then-Preferred Plan had Energy Center 1  
6 and 2 slated for retirement in the 2025 timeframe. However, during the 2022 IRP, and  
7 reaffirmed in the 2025 IRP, we extended the operating life of those units out to 2035  
8 because they demonstrated significant winter reliability. If the Company's future IRP  
9 analyses determine that it is once again cost-effective and reliable to extend the life of  
10 Energy Center 1 and 2 beyond 2035, the "need" for the J-Class turbines extra 170 MW  
11 off capacity in that timeframe would be deferred to a future time period. By selecting  
12 the F-Class turbine, supported by the Company's IRP analysis, the Company is  
13 addressing its immediate and confirmed capacity shortfall while preserving future  
14 planning flexibility and avoiding the risk of burdening customers with excess capacity  
15 that may not be optimizable through off-system sales.

16 **VI. STAFF REPORTING REQUIREMENT – ITEM 16**

17 **Q. What is the purpose of this section of your surrebuttal testimony?**

18 A. The purpose of this section is to address Staff's proposed Reporting Requirement 16.  
19 As I understand the recommendation, Staff proposes that, for future CCN applications  
20 in which Liberty relies on IRP analysis, Liberty should be required to perform cost  
21 analysis on an individual project basis, provide updated IRP analysis under certain  
22 circumstances, conduct comprehensive market risk assessments and economic  
23 modeling for alternative technologies, identify cost mitigation techniques, and provide  
24 detailed risk mitigation plans. The Company appreciates Staff's interest in ensuring

1 that future CCN applications are supported by meaningful and current information.  
2 However, I have concerns that Reporting Requirement 16, as drafted, is unclear,  
3 potentially unworkable, and may blur the distinction between the current IRP process  
4 and the project-specific analysis that is more appropriately developed in connection  
5 with a specific CCN application.

6 **Q. What is the Company's primary concern with Staff's proposed Reporting**  
7 **Requirement 16?**

8 A. The Company's primary concern is that Staff's proposed condition appears to require  
9 project-specific precision at a point in the planning process where the current IRP rules  
10 necessarily rely on broader assumptions, sensitivities, and portfolio-level analysis.  
11 Under the current IRP framework, the Company evaluates alternative resource plans  
12 across a planning horizon and assesses them using multiple performance measures,  
13 including present worth of utility revenue requirements, probable environmental costs,  
14 risk, reliability, and other planning objectives. The IRP process is designed to evaluate  
15 resource strategies under uncertainty; it is not intended to function as a fully  
16 engineered, site-specific procurement process for every possible alternative resource.

17 A CCN application serves a different function. At that stage, the Company  
18 presents a specific project, supported by more refined project information, including  
19 site due diligence, development status, engineering, transmission and interconnection  
20 considerations, permitting considerations, commercial terms, and cost estimates. Those  
21 two processes are related, but they are not interchangeable.

22 **Q. Why is that distinction important?**

23 A. It is important because there is an inherent tradeoff between breadth and specificity.  
24 The IRP process provides breadth. It evaluates a wide range of resource portfolios,

1 technologies, assumptions, sensitivities, and critical uncertain factors. That breadth is  
2 valuable because it allows the Company and stakeholders to understand how different  
3 resource strategies perform under different future conditions. Project development  
4 provides specificity. It narrows the analysis to a particular resource, site, technology,  
5 interconnection path, permitting profile, equipment configuration, and commercial  
6 structure. That specificity is also valuable, but it requires time, money, and a level of  
7 project commitment that is not practical for every hypothetical resource alternative  
8 evaluated in an IRP. Staff's proposed condition appears to demand both at the same  
9 time: broad IRP sensitivity analysis and detailed project-level analysis for alternative  
10 resources that may never be pursued. In my view, that is not a reasonable or efficient  
11 planning standard.

12 **Q. Do the current IRP rules already require the Company to evaluate alternative**  
13 **resources and risk?**

14 A. Yes. The current IRP rules require a robust evaluation of alternative resource plans.  
15 The rules require the Company to consider demand-side resources, renewable  
16 resources, and supply-side resources on an equivalent basis, and to use minimization  
17 of the present worth of long-run utility costs as the primary selection criterion, subject  
18 to other critical considerations. The rules also require the Company to consider risks  
19 associated with critical uncertain factors, legal mandates, and rate impacts.

20 In other words, the current IRP process is already designed to evaluate resource  
21 alternatives and uncertainty. My concern is not with providing meaningful analysis.  
22 My concern is with converting a planning-level IRP into a requirement to perform  
23 detailed, site-specific project development work for multiple alternatives before the  
24 Company has identified which resource is actually being advanced for approval.

1 **Q. Do you have concerns with Staff’s proposed use of a “\$/kWh” comparison in**  
2 **Reporting Requirement 16?**

3 A. Yes. The Company’s IRP does not select resources based solely on a static \$/kWh  
4 comparison. It evaluates portfolios using broader performance measures, including  
5 long-run revenue requirement impacts, reliability, risk, and other planning  
6 considerations. Staff’s proposed language could unintentionally elevate a narrow cost  
7 metric over the broader planning framework required by the current IRP rules.

8 **Q. Do you also have concerns with Staff’s reference to “another resource type that is**  
9 **capable of satisfying the need identified for the CCN application”?**

10 A. Yes. That phrase is also unclear. The need identified in a CCN application is not  
11 necessarily satisfied by any resource that can produce energy or that appears as the  
12 lowest cost under one metric. The relevant question is whether the resource can satisfy  
13 the specific need at issue, in the relevant timeframe, with acceptable reliability,  
14 deliverability, development, permitting, transmission, and execution risk.

15 For this case, the need is not simply an energy need. It is a capacity and  
16 reliability need, particularly in light of SPP’s resource adequacy requirements and the  
17 Company’s winter capacity position. A resource that is theoretically lower cost or  
18 technologically available may still not be capable of satisfying that need in the required  
19 timeframe or with comparable reliability value.

20 **Q. Is it practical to require updated IRP analysis whenever project-specific costs**  
21 **differ from planning assumptions?**

22 A. Not as Reporting Requirement 16 appears to be drafted. The Company agrees that  
23 material changes in cost, need, timing, or project assumptions should be explained in a  
24 CCN application. But requiring a new or updated IRP analysis whenever a project cost

1 comparison changes under an undefined \$/kWh metric could create a circular and  
2 inefficient process.

3 Project costs, EPC pricing, equipment availability, transmission assumptions,  
4 interconnection requirements, permitting conditions, and financing assumptions can all  
5 change during project development. If each material movement requires a new IRP  
6 analysis before the Company can proceed, the analysis may never fully catch up to the  
7 market. By the time the updated IRP analysis is completed, the underlying commercial  
8 information may have changed again.

9 **Q. Are you suggesting that future CCN applications should rely on stale IRP**  
10 **assumptions?**

11 A. No. The Company should provide the best information reasonably available at the time  
12 of a CCN filing. If material assumptions have changed since the IRP, the Company  
13 should explain those changes and demonstrate why the proposed project remains  
14 reasonable and necessary. That is different from requiring the Company to rerun an  
15 IRP or develop project-level cost estimates for multiple alternative resources that have  
16 not been selected for development. A more reasonable approach is to require a material-  
17 change explanation in the CCN filing, supported by updated project information, rather  
18 than imposing an open-ended requirement to recreate the IRP with project-specific  
19 precision.

20 **Q. Do you have any concern that Reporting Requirement 16 may be attempting to**  
21 **incorporate future, proposed IRP requirements before those rules are finalized?**

22 A. I do have that concern. I do not want to speculate as to Staff's intent, but Reporting  
23 Requirement 16 appears to reach beyond the current Chapter 22 IRP framework and

1 impose additional requirements for future CCN applications that may overlap with  
2 issues being considered as part of the broader SB 4-related IRP rulemaking process.

3 If the Commission, Staff, utilities, and other stakeholders are in the process of  
4 developing new IRP rules, those requirements should be addressed through that  
5 rulemaking process, where all affected parties can participate and the Commission can  
6 adopt generally applicable standards. I do not believe it is appropriate to impose what  
7 may function as a future IRP rule through a project-specific CCN condition before  
8 those rules have been finalized.

9 **Q. Why would that be problematic?**

10 A. It would be problematic because a CCN condition in this case would apply to Liberty  
11 before the broader rulemaking process has concluded and before the Commission has  
12 adopted generally applicable standards. That creates uncertainty and could impose  
13 obligations on Liberty that are different from, or potentially inconsistent with, the final  
14 rules ultimately adopted. The Company is not opposed to reasonable reporting  
15 requirements or future improvements to the IRP process. But those requirements should  
16 be clear, consistently applied, and adopted through the appropriate procedural vehicle.  
17 A project-specific CCN case is not the appropriate forum to create new planning  
18 obligations for future IRPs and future CCN applications.

19 **Q. What is your recommendation to the Commission regarding Staff's proposed**  
20 **Reporting Requirement 16?**

21 A. I respectfully recommend that the Commission reject Reporting Requirement 16 as  
22 proposed. The Company supports transparent, well-supported CCN applications and  
23 recognizes that future filings should explain any material changes from the IRP  
24 assumptions on which the Company relies. However, Reporting Requirement 16 is

1           unclear in several important respects and appears to require a level of project-specific  
2           analysis that is not reasonably available during the IRP process. A more practical  
3           approach would be to require the Company, in any future CCN application that relies  
4           on IRP analysis, to identify material changes in cost, timing, need, technology,  
5           transmission, permitting, or risk assumptions since the IRP was completed, and to  
6           explain why the proposed project remains reasonable and necessary in light of those  
7           changes. That approach would preserve the value of the IRP process, provide the  
8           Commission and parties with meaningful updated information, and avoid creating an  
9           unworkable standard that could delay needed capacity additions or require costly  
10          development work for alternatives that may never be pursued.

11   **VII. REMOVAL OF SOLAR, DSM, BESS**

12   **Q.    What is the purpose of this section of your surrebuttal testimony?**

13   A.    The purpose of this section is to respond to the criticisms raised by Renew Missouri  
14          Witness Philip A. Fracica. Specifically, I will address concerns regarding the  
15          Company’s decision to remove Demand-Side Management (“DSM”) and a 175 MW  
16          solar project in our October 2025 Preferred Plan Update, as well as the claim that this  
17          decision negatively impacts low-income customers.

18   **Q.    Mr. Fracica argues that the Company placed an undue emphasis on natural gas**  
19          **while failing to adequately evaluate non-wires alternatives like Battery Energy**  
20          **Storage Systems (“BESS”). Do you agree?**

21   A.    No. Mr. Fracica’s critique ignores the rigorous technology evaluations conducted in  
22          our 2025 IRP. The IRP explicitly evaluated multiple storage technologies on an  
23          equivalent basis with supply-side resources, including 4-hour lithium-ion batteries, 8-  
24          hour flow batteries, and gravity storage. However, the primary driver for our immediate

1 generation need is the SPPs increasing winter PRM. To meet this strict winter mandate  
2 reliably, our modeling demonstrated that adding a dispatchable F-Class combustion  
3 turbine provided the most cost-effective and resilient solution.

4 **Q. Why did the Company remove the 175 MW solar project from the Preferred Plan**  
5 **Update?**

6 A. The removal of the near-term solar project was directly driven by SPP's move to a  
7 seasonal accreditation framework. Under these new rules, solar generation is assigned  
8 a very limited capacity value during the winter season. Because our system is  
9 increasingly winter-constrained due to the new SPP mandates, a near-term solar  
10 addition simply created a mismatch with our actual winter capacity needs. However, it  
11 is important to note that utility-scale solar remains a part of the Company's long-term  
12 strategy, with an addition currently planned for 2035.

13 **Q. Mr. Fracica claims the removal of DSM programs was driven by "regulatory**  
14 **uncertainty" rather than a lack of cost-effectiveness. Why were these programs**  
15 **removed?**

16 A. The DSM programs were removed to reflect actual regulatory reality. The  
17 discontinuation of these programs followed the Missouri Public Service Commission's  
18 own concerns regarding our Missouri Energy Efficiency Investment Act ("MEEIA")  
19 Cycle 2 application's alignment with statutory intent. Those concerns led to the formal  
20 withdrawal of that filing in April 2025. Consequently, the Company updated its  
21 Preferred Plan to ensure it reflected realistic, actionable assumptions moving forward.

22 **Q. Mr. Fracica asserts that by eliminating DSM and the solar project, the Company**  
23 **is increasing costs for all ratepayers, particularly low-income customers. Is this**  
24 **accurate?**

1 A. No, it is demonstrably incorrect. As detailed in the October 2025 Preferred Plan  
2 Update, removing the firm solar project and the near-term DSM programs actually  
3 *lowered* the plan’s 20-year Present Value of Revenue Requirement (“PVR”) by  
4 roughly \$58 million, and its 30-year value by \$34 million relative to the April 2025  
5 version.

6 **Q. On page 11 of his direct testimony, Renew Missouri Witness Philip Fracica**  
7 **recommends that the Company conduct a comprehensive evaluation of demand-**  
8 **side resources, explore hybrid resource portfolios, and reassess the role of**  
9 **Demand-Side Management (“DSM”) programs regarding peak demand and**  
10 **customer affordability. Do you agree that the Commission should impose these as**  
11 **new reporting requirements?**

12 A. No, I do not. While I appreciate Mr. Fracica’s focus on these areas, his  
13 recommendations request analysis that the Company already performs rigorously as a  
14 standard part of the IRP process. As mandated by the Commission’s own rules (20 CSR  
15 4240-22), the IRP already requires the Company to evaluate demand-side and supply-  
16 side resources on an equivalent basis. Therefore, imposing these recommendations as  
17 new, separate reporting requirements or conditions in this CCN proceeding is  
18 unnecessary and duplicative.

19 **Q. Since these evaluations are already part of the IRP process, how does the**  
20 **Company plan to address Mr. Fracica’s specific recommendations moving**  
21 **forward?**

22 A. Because the IRP process inherently encompasses these evaluations, the Company will  
23 seamlessly continue to meet these objectives through our standard, ongoing regulatory  
24 filings. Specifically, the Company commits to the following positions:

- 1           • The Company will continue to conduct a comprehensive evaluation of demand-side  
2           resources, including energy efficiency and demand response, within the IRP.
- 3           • The Company will continue to explore hybrid resource portfolios that combine  
4           smaller-scale generation with distributed resources within its IRP.
- 5           • The Company will, as appropriate, evaluate DSM program considerations related  
6           to peak demand and customer affordability, consistent with existing regulatory  
7           frameworks.

8   **VIII. SPECULATIVE DATA CENTER LOAD**

9   **Q.    What is the purpose of this section of your surrebuttal testimony?**

10 A.    The purpose of this section is to address and correct the record regarding OPC Witness  
11       Dr. Geoff Marke's claim that the Company is using "speculative" data center load to  
12       justify the investment in the 250 MW F-Class combustion turbine.

13 **Q.    Did the Company's base load forecast, which supports the Preferred Plan and this**  
14 **proposed investment, include a data center?**

15 A.    No, it did not. Liberty did not add any new data centers in its base case. The largest  
16       driver for this 250 MW facility is the tightening winter planning reserve margins  
17       mandated by the SPP, not a speculative data center.

18 **Q.    Did the Company evaluate a data center scenario at all during the Integrated**  
19 **Resource Plan ("IRP") process?**

20 A.    Yes, as a Special Contemporary Issue as ordered by the Commission. In that specific  
21       scenario, Liberty modeled an additional 300 MW of data center load materializing by  
22       2031. The analysis demonstrated that if a data center were actually built, the additional  
23       load would require significantly more resources for adequacy, resulting in plans that  
24       were roughly 10-15% higher in cost over a 20-year present value basis. A data center

1 would require substantially more capacity than what the Company is currently  
2 proposing, and it is factually incorrect to suggest this 250 MW F-Class turbine is being  
3 built to serve a data center or due to a speculative data center load.

4 **Q. Do you find any inconsistency in the positions taken by OPC regarding the size of**  
5 **the proposed unit and “speculative” load?**

6 A. Yes. There is a clear tension between the positions. On one hand, Dr. Marke cautions  
7 against investment in this generating unit on the basis that it would serve what he  
8 characterizes as speculative load. On the other hand, Mr. Robinett, who represents the  
9 same Office of the Public Counsel as Dr. Marke, suggests that the Company should  
10 have evaluated a much larger 420 MW J-Class unit instead of the proposed 250 MW  
11 F-Class unit.

12 **Q. Why is that inconsistent?**

13 A. It is inconsistent because Mr. Robinett suggests that a significantly larger unit may have  
14 been preferable, at least in part, to serve potential future load growth, the very type of  
15 load Dr. Marke cautions the Commission not to rely upon. The Company’s approach  
16 avoids that inconsistency. Rather than overbuilding around uncertain future demand,  
17 the Company selected the F-Class unit because it is aligned with the Company’s actual,  
18 known base-case capacity need, is supported by the IRP analysis, and preserves future  
19 planning flexibility. This is a prudent, least-cost approach that addresses the  
20 Company’s immediate capacity shortfall without unnecessarily burdening customers  
21 with additional capacity that may not be needed or capable of being optimized through  
22 off-system sales.

1 **IX. CWIP**

2 **Q. OPC Witness Geoff Marke claims that your quote in a recent *Joplin Globe* article**  
3 **stating that consumers wouldn't see the costs of the project until after 2030**  
4 **contradicts the Company's request to establish eligibility for Construction Work**  
5 **In Progress ("CWIP") recovery. How do you respond to this?**

6 A. I stand confidently by the information I provided to the press, but OPC is relying on an  
7 incomplete summary of my statements to make their argument. The published article  
8 was a brief summary of a 30-minute interview, and it clearly left out a crucial regulatory  
9 distinction that I made during that conversation. When I discussed costs being passed  
10 on to the consumer after 2030, my comments were specifically directed at when  
11 customers would begin paying the full cost of the generating unit through base rates.  
12 That full recovery will only occur after the unit is placed in service and incorporated  
13 into a future rate proceeding.

14 **Q. How does that distinction make the article consistent with the Company's**  
15 **consideration of CWIP?**

16 A. CWIP and full rate base recovery are not the same thing. CWIP represents recovery of  
17 a portion of prudently incurred construction costs during construction; it does not  
18 constitute recovery of the full cost of the resource. By contrast, the public-facing  
19 discussion in the article concerned the broader timing of when customers would see the  
20 full cost of the generating unit reflected in rates after the project is completed and  
21 placed in service.

22 Therefore, the statements summarized in the article and the Company's  
23 evaluation of CWIP are not inconsistent. OPC's argument treats a general newspaper

1 summary as though it were a complete ratemaking explanation, but the article did not  
2 purport to address every potential cost-recovery mechanism available to the Company.

3 **Q. Does this conclude your surrebuttal testimony at this time?**

4 **A.** Yes, it does.

**VERIFICATION**

I, Aaron J. Doll, under penalty of perjury, on this 27th day of May, 2026, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Aaron J. Doll