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Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Dmitry Balashov

on behalf of

The Empire District Electric Company d/b/a Liberty

November 6, 2024

Liberty™

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dmitry Balashov, and my business address is 354 Davis Road, Oakville, Ontario, Canada.

Q. By whom are you employed and in what capacity?

A. I am employed by Liberty Utilities (Canada) Corp. ("Liberty Canada") as a Senior Director, Grid Modernization. In this capacity I support evaluation and adoption of emerging customer and utility side distribution technologies, work to expand the application of modern asset management tools and principles on conventional distribution plant, and oversee advanced metering strategy across Liberty's affiliates across the United States. In recent years, I also led preparation of multiple infrastructure grant applications to the U.S. Department of Energy ("DOE") under the Grid Resilience and Innovation Partnerships ("GRIP") program arising from the bipartisan Infrastructure Investment and Jobs Act, 2021 ("IIJA") legislation.

In performing my duties, I work closely with local engineering, planning, operations, program delivery, and regulatory subject matter experts, including employees supporting the electric operations of The Empire District Electric Company d/b/a Liberty ("Liberty" or the "Company") in Missouri.

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

A. I am testifying on behalf of Liberty.

Q. Please describe your educational and professional background.

A. I hold a bachelor's degree in political science from the University of British Columbia in Vancouver, BC, Canada, which I completed in 2005. I also obtained a master's degree in public administration with concentration in energy policy from Queen's University in Kingston, ON, Canada, completed in 2008. Finally, I hold an Executive Master of Business Administration degree from the Rotman School of Management at the University of Toronto, ON, Canada, which I completed in 2018.

I started my career in the electric industry in 2007 at the Transmission and Distribution Policy Division of Ontario, Canada's Ministry of Energy, where I held several advisory positions in support of electrical infrastructure planning and regulatory policy matters. Between 2013 and 2017 I was employed by Toronto Hydro Electric System Limited – Canada's largest urban distribution utility at the time – where I worked as a Lead of Process and Analytics. My position primarily entailed identifying, obtaining regulatory approval for, and implementing a variety of operations and capital planning and asset management initiatives aimed at enhancing system reliability and labor and capital productivity.

Between January 2017 and February 2021, I worked as a Director of Utility Strategy and Economic Regulation at METSCO Energy Solutions Inc., a utility sector engineering and asset management consultancy. My primary area of responsibility was development of risk-based asset management plans that helped transmission and distribution utilities identify, pace, and prioritize the highest-value capital projects and maintenance program enhancements based on objective quantitative analysis of asset health, connectivity, and reliability performance. I joined Liberty in February 2021 as a Senior Director of Policy and Strategy and transitioned to my current role of Senior Director of Grid Modernization in early 2022.

Q. Have you previously testified before the Missouri Public Service Commission ("Commission")?

A. I have not. However, I represented Liberty and closely collaborated with Commission Staff, the Missouri Office of the Public Counsel ("OPC"), and other participants in the Company's 2020 Transportation Electrification Pilot Program application (ET-2020-0390).

Q. Have you testified in other regulatory jurisdictions?

A. Yes, I testified on behalf of Liberty's affiliates before the Kentucky Public Service Commission and the New Hampshire Public Utilities Commission. I also submitted written testimony to several Canadian utility sector regulators, including the Ontario Energy Board, the Manitoba Public Utilities Board, and the Alberta Utilities Commission.

Q. What is the purpose of your direct testimony?

A. I provide updates on several facets of Liberty's Grid Modernization work that directly arose from its settlement commitments from its last rate application (Case No. ER-2021-0312) and the aforementioned Transportation Electrification docket (Case No. ET-2020-0390). I also provide an update on the Company's activities pertaining to the DOE's GRIP program grant applications, a process in which the Company has been very active over the last 21 months. More specifically, my testimony provides updates on the following matters:

- Voltage Optimization Study
- Value of Lost Load Study
- Cost-Benefit Analysis for Projects Over $1M
- The Transportation Electrification Pilot Program

- The DOE GRIP Program
- Changes to the Company's Missouri Emergency Conservation Plan tariff

II. VOLTAGE OPTIMIZATION STUDY UPDATE

Q. What is the background of the Voltage Optimization ("VOPT") study?

A. The VOPT study was among the terms of Liberty's Fourth Partial Stipulation and Agreement in Case No. ER-2021-0312. The specific language pertaining to this item is:

> Empire will issue a request for proposals for an independent, third-party consultant to conduct a study in calendar year 2022 of its distribution system designed to gauge the costs and benefits of a voltage optimization program in Empire's service territory. Empire will meet with Staff and OPC to discuss the RFP responses and possible next steps.[1]

The primary impetus for the study was the OPC's interest to explore whether or to what extent the Company's distribution circuits may be operating at a higher than optimal voltage level, and if so, whether the introduction of additional voltage optimization equipment (beyond the existing capacitor banks and their current settings) could lead to higher energy conservation, lower customer bills, and higher distribution system efficiency.[2] The Company saw merit in proceeding with the study, provided it was carried out efficiently and resulted in incremental insights and opportunities to capture more field equipment data that we would use to further expand our risk-based planning capabilities discussed in the section of my testimony dedicated to cost-benefit-analysis frameworks. Of particular interest for the Company in the context of this exercise was collecting and verifying existing data related to the distribution conductor health and rating demographics, which will become increasingly critical for system planning and

[1] ER-2021-0312, Fourth Partial Stipulation and Agreement, p.2, February 05, 2022.
[2] ER-2021-0312, Rebuttal Testimony of Geoff Marke, pp. 34-35, December 20, 2021.

load flow simulation as the penetration of distributed energy resources ("DERs") continues to grow over time.

Q. Did the Company fulfill its settlement commitments pertaining to the VOPT study?

A. Yes. The Company issued a request for the expression of interest ("RFEI"), which is equivalent to a request for proposals ("RFP"), on the VOPT study to eleven North American engineering firms and received five responses confirming interest. The Company provided a copy of the RFEI and the contents of bidder response packages to OPC and Staff during a meeting on September 27, 2022. After the meeting, the parties agreed that 1898 & Co. (a consulting arm of Burns & McDonnell) was the preferred bidder. The Company engaged 1898 & Co., and the work began in late 2022, continued through 2023, and concluded in 2024. The resulting study report is attached to my testimony as **Direct Schedule DB-1**.

Q. Please describe the study's scope and key analytical steps.

A. Because the Company's distribution system consists of over 300 feeders, the local subject matter experts ("SMEs") from the Planning, Engineering, and Operations departments selected a representative sample of seven feeders that would undergo the detailed study. In selecting the sample, the SMEs sought to reflect a mix of customer classes, customer density (e.g. more urban vs. rural), service types (e.g. overhead and underground), and circuit lengths that capture the diversity of the Company's expansive distribution grid.

The Company informed 1898 & Co. of the selected sample and provided it with available GIS asset records, feeder-connected load data, hourly substation transformer loading, and feeder-specific loading information. As a first step, the consultant performed feeder walk-downs and detailed visual inspections to verify the available information on feeder equipment ratings and fill any data gaps. Upon completing the feeder walkdowns, 1898 & Co. developed detailed feeder models using a load flow simulation software that integrated all the data it obtained from the Company or collected in the field.

The models then examined the current state of feeders' operating characteristics including secondary voltage variation along the feeder, power factor ranges, and phase balancing. Existing capacitor bank placement and operational settings were accounted for in this analysis to quantify their impact on existing voltage regulation and power factor control. Where interim VOPT results suggested that some degree of power factor adjustment could be feasible or desirable relative to the starting assumptions, 1898 & Co. developed and modelled hypothetical system enhancements, such as adding or relocating new capacitor banks or changing bank control algorithms at locations as specific as individual poles.

As a final step in the study, the consultant performed a cost-benefit analysis exercise to determine the net economic value of incremental hypothetical system enhancements modelled in the previous step. The hypothetical power factor efficiency gains or improvements to voltage regulation were monetized and evaluated against the estimated costs of attaining them using discounted cashflow ("DCF") analysis. The study presented the results of this work also discussing the directional implications of its findings system-wide.

Q. What does the study conclude?

A. The study found no systemic issues with the representative sample of seven feeders that were studied in detail and concludes that the theoretical equipment enhancements that it explores would offer little to no customer value. While some enhancements could be feasible and beneficial from a purely technical perspective, their value proposition is notably diminished by the estimated cost of equipment modifications that would be required to obtain them.

Q. What conclusions can be made from the VOPT study with respect to voltage issues on the Company's system overall?

A. Consistent with 1898 & Co.'s observations in the report, the Company acknowledges that voltage analysis is a highly location-specific exercise, which makes it challenging to generalize. This is because feeder-specific factors like number, size, peak allocation share and types of customer loads (e.g. resistive, inductive, capacitive), distances between loads, default equipment ratings, and number of phases, can create unique considerations in each case. As such, the study does not provide a basis to conclude that there are no individual improvement opportunities across the Company's 300+ distribution feeders. However, it is notable that 1898 & Co.'s study has neither identified any significant opportunities for customer savings, nor encountered any systemic issues (i.e. presence of results across feeders that would indicate a broader consistent pattern of under-performance) in their analysis of Liberty's feeders. While further examination is certainly possible, nothing in the study's results gives us grounds to suspect that current Company standards or the actual performance of voltage support devices in the field warrant broader and deeper reassessment than what occurs in the context of regularly scheduled activities.

III. VALUE OF LOST LOAD STUDY UPDATE

Q. What is the background of the Value of Lost Load ("VOLL") study?

A. The VOLL study was another commitment agreed upon between the Company and the other parties to the Fourth Partial Stipulation and Agreement in Case No. ER-2021-0312:

> Empire, in consultation with Staff and OPC, will engage a consultant to develop a Value of Lost Load ("VOLL") study. Empire will issue a competitive request for proposal. Staff and OPC will have input on the selection of the consultant and the scope and timing of the study. Empire will be allowed to recover the costs of the study. Staff, OPC, and Empire, jointly, may elect not to pursue a VOLL study in the event the cost outweighs the expected benefits of such a study. When the study is complete, the Signatories may recommend to the Commission changes to Empire's tariff they believe are supported by the study's results. The Signatories also agree that Empire will immediately begin a review of its Emergency Conservation Plan and determine if any enhancements or improvements would be beneficial. Following that review, Empire will make a filing with the Commission proposing tariff changes or stating that Empire believes no such changes are needed.[3]

Q. What is a VOLL study?

A. A VOLL study is a rigorous econometric analysis of interview responses from a large sample of electric customers of every type – from residential to industrial – that attempts to quantify the economic cost customers incur due to electric service interruptions under a variety of scenarios (e.g., different seasons, interruption durations, or other scenario-specific circumstances contemplated in the study).

Q. What is the status of the VOLL study?

A. Consistent with the terms of the Stipulation, the Company issued an RFEI to four consulting firms that our initial research indicated had the requisite capabilities to complete a study this methodologically nuanced, quantitatively and logistically

[3] ER-2021-0312, Fourth Partial Stipulation and Agreement, p.3, February 05, 2022.

complex, and voluminous. Three of the vendors returned their bids, which the Company subsequently shared with Staff and OPC. As with the VOPT, the parties agreed on the preferred bidder, a collaboration between Resource Innovations Inc. (formerly Nexant) and Lawrence Berkeley National Laboratory ("Berkeley Lab").

Q. What was the significance in selecting this vendor?

A. Resource Innovations Inc. ("RII") and Berkeley Lab developed the original Interruption Cost Estimate ("ICE") Calculator endorsed by the United States Department of Energy, which has been publicly available and relied upon for many years.[4] Currently, the Edison Electric Institute ("EEI") has partnered with RII and Berkeley Lab to conduct a comprehensive update of the ICE calculator by deploying renewed surveys across the United States. By joining this initiative, the Company is contributing to an important energy industry research endeavor on a national scale. Liberty learned after meeting with Berkeley Lab representatives that there was no Midwest representation in the initiative until their declaration of interest. Along with the Company, Evergy Missouri and Ameren Missouri also joined the initiative. Midwestern utility participation is critical because the original ICE calculator was not based on any Midwestern data.

Q. Is there anything else notable about the VOLL study?

A. Yes. VOLL studies are very expensive, with the initial amount quoted to each of the three Missouri utilities being $800,000. While the study's objectives were of great interest to all three Missouri utilities, the cost was a significant concern, especially because there was no clear consensus among stakeholders as to how the VOLL studies' results would be used and what conclusions could be drawn from their results at the

[4] https://icecalculator.com/home, accessed 03/20/24.

outset. Given that VOLL studies involve a large volume of survey work, financial document review, and econometric analysis of each utility's sample of customers, the utilities learned that there were few economies of scale or scope that would materially reduce the cost even with all Missouri IOUs participating in the study at the same time.

That notwithstanding, OPC was instrumental in negotiating the cost per study down to $600,000 per study. However, even with that reduction, the IOUs' consensus view was that the price tag was challenging to justify despite the universal interest in exploring the associated insights.

Q. What steps did the Company take to help resolve this issue?

A. The Company suggested a compromise approach in which only one utility's customer base would undergo the study, acting as a proxy for all Missouri IOUs in what is essentially an experimental attempt for Missouri's regulated utilities. Under such an arrangement, only one study would be performed, with each utility bearing roughly a third of the cost each would have incurred for its own VOLL study. Given that Ameren's and Evergy's service territories include both significant rural and urban areas, the Company suggested it would be reasonable to segment the study's results to allow for adjustments to reflect the circumstances of particular utilities. Since no part of its service territory contains the type of customer density characteristic of large parts of the urban areas that Evergy and Ameren serve, the Company's customer base was not an optimal candidate to act as a proxy utility. Fortunately, Ameren representatives volunteered to conduct the study with its customers.

Staff and OPC deserve credit for supporting the three utilities in this deviation from the original plan and seeing merit in balancing the objectives of advancing empirical planning research with those of managing the ensuing customer impacts.

Q. What is the current status of the study?

A. The study is in its preliminary stages. The vendor informed all the parties at the outset that the study could not be completed until 2025, largely due to queue of multiple other EEI member VOLL studies that were agreed upon before the Missouri utilities' arrangements were finalized.

For its part, the Company has made all necessary payments for the study and provided its input on a small subset of customized survey questions that can be added to the standard VOLL survey and interview package to obtain some incremental insights that extend beyond the core study. Most recently, the Company has provided the vendors with information about its customer mix to help ensure that Ameren customers selected for interviews were sufficiently representative of Liberty's customers.

Q. Is the Company confident that the "proxy utility" approach that this study adopted will yield the outputs that will appropriately reflect each utility's local customer interruption cost economics and other related considerations?

A. The study's outputs will be a major enhancement to the current state of customer interruption cost research in the Midwest, which is based on publicly available inputs derived from non-Midwestern utility studies, most of which are decades old. Such inputs largely precede critically relevant phenomena that impact today's customer interruption cost economics, ranging from ubiquitous work-from-home arrangements and the gig economy to mega data centers, behind-the-meter generation and storage, and electric transportation. While a utility-specific study would always be the optimal approach, it is not cost effective for customers given the lack of consensus on whether and how the study's results should be used. Overall, there is no doubt that this study's results will be a significant step forward for Missouri's and Liberty's utility planning and rate design research.

Q. What are the use cases for the VOLL study's outputs?

A. The study's results will have multiple uses, including as inputs to cost-benefit calculations for projects with reliability-enhancing benefits. While outage response results in utilities incurring additional costs (e.g. overtime labor, additional truck rolls, and lost revenues) that are possible to quantify, Customer Interruption Costs ("CICs") that VOLL studies produce help planners quantify the full economic cost of outages by including the economic costs incurred by customers as a result of losing their power supply. Depending on customer class, these can include costs as widely varying as food spoiled in someone's freezer, a dead laptop battery that temporarily affects an individual's ability to earn income, a gas station unable to dispense fuel, a spoiled batch of unfinished goods on the manufacturing assembly line, or a data center's reduced uptime that affects its contractual obligations to customers.

Q. Is this the context in which the Company primarily plans to use the results of the study?

A. Yes. As I discuss in the next section of my testimony, the VOLL study should provide key inputs into the cost-benefit-analysis calculation framework the Company is developing consistent with another settlement commitment. If this framework functions as expected, there will be opportunities to integrate VOLL outputs further into risk management calculations, customer service metrics, financial forecasting, and others. In the interim, we look forward to the completion of the study and reviewing its results.

Q. As part of the Fourth Partial Stipulation and Agreement in Case No. ER-2021-0312, Liberty agreed to review its Emergency Conservation Plan and determine if any enhancement or improvements would be beneficial. Has the Company completed a review of its Emergency Conservation Plan?

A. Yes. The Company has reviewed its Missouri Emergency Conservation Plan tariff and is making several revisions to align its tariff with its Emergency Operations Procedures manual. The changes to the tariff are being included herewith my testimony as **Direct Schedule DB-2**.

IV. COST-BENEFIT ANALYSIS FOR PROJECTS OVER $1M

Q. What is the background of this update item?

A. Similar to the two studies discussed above, the commitments regarding developing and implementing a cost-benefit analysis framework for projects exceeding a $1 million cost threshold were captured in the Fourth Partial Stipulation and Agreement in Case No. ER-2021-0312:

> Empire will meet with Staff and OPC at least twice regarding "parameters and assumptions" and will provide to Staff and OPC, with HC confidentiality protection, cost-benefit analyses and performance metrics for planned capital investments of greater than $1 million. Empire agrees to file the cost-benefit analyses and performance metrics in its PISA [Plant in Service Accounting] docket and update annually.[5]

Q. What is the status of fulfilling the Company's commitments related to this commitment?

A. The Company is well on its way to meeting this commitment. As the Company explained when it met with Staff and OPC to discuss this and other Stipulation commitments on September 27, 2022 and February 24, 2023, this commitment creates

[5] ER-2021-0312, Fourth Partial Stipulation and Agreement, p.2, February 05, 2022.

an opportunity to enhance the way the Company conducts infrastructure planning analysis, especially for transmission and distribution ("T&D") renewal projects, which are among the highest-volume components of its overall capital program. Specifically, the Company's proposal to meet this settlement commitment was to develop and implement a project Cost-Benefit Analysis ("CBA") framework consisting of new tools and modified analytical processes grounded in principles of modern risk-based utility asset management, which I describe below.

The Company acknowledged during its meetings with Staff and OPC that although less time- and resource-intensive paths existed for meeting the requirements of this Stipulation commitment, the additional time and effort needed to establish a solution that takes a significant step forward in how the Company evaluates and prioritizes among capital T&D projects was worthwhile. Accordingly, and as the Company communicated in both of its 2023 and 2024 PISA filing updates, and subject to any unforeseen developments, the Company expects to provide the CBA and/or performance metrics information for planned capital investments greater than $1 million as a part of its 2025 PISA update filed in the associated docket.

Q. What specifically did the Company propose?

A. To meet this settlement commitment, the Company proposed to implement a new Cost Benefit Analysis Automation Tool ("CBAT") to conduct quantitative cost-benefit analysis based on a range of inputs, which will enable the Company's system planners to perform relative prioritization across individual T&D renewal and enhancement projects contemplated for delivery in new and enhanced ways. Consistent with the Stipulation commitments, the Company has also presented several potential performance metrics options it is evaluating for tracking in its planning and asset management functions.

Q. Please describe the CBAT.

A. The CBAT is based on a commercial asset management analytics package named ENGIN, developed by Engineered Intelligence Inc.[6] The Company selected ENGIN after an extensive evaluation process that also explored three other commercially available solutions. ENGIN is the optimal foundation for the CBAT based on a combination of factors including cost, robustness of the underlying methodology, range and maturity of available supporting modules, and technical support.

At the core of the CBAT are the principles of risk-based asset management as captured in the ISO55000 group of standards.[7] Risk-based asset management in the utility space is about selecting an optimal portfolio of system investments based on a systematic assessment of available data that estimates the probability and dollar impact of various undesirable outcomes associated with the functions performed by the utility's T&D asset base (e.g., equipment failures, substation capacity shortages) and evaluates the potential means of mitigating these outcomes through a range of available asset intervention options. Depending on the equipment in question, these options can include asset replacement (with or without capacity expansion or addition of new features and capabilities), incremental equipment maintenance or refurbishment, feeder looping, or a deferral of a given project relative to other opportunities to deploy the utility's labor or capital resources. Not all these options are applicable for every project or will be available for the Company to use from the outset as it gains comfort with the

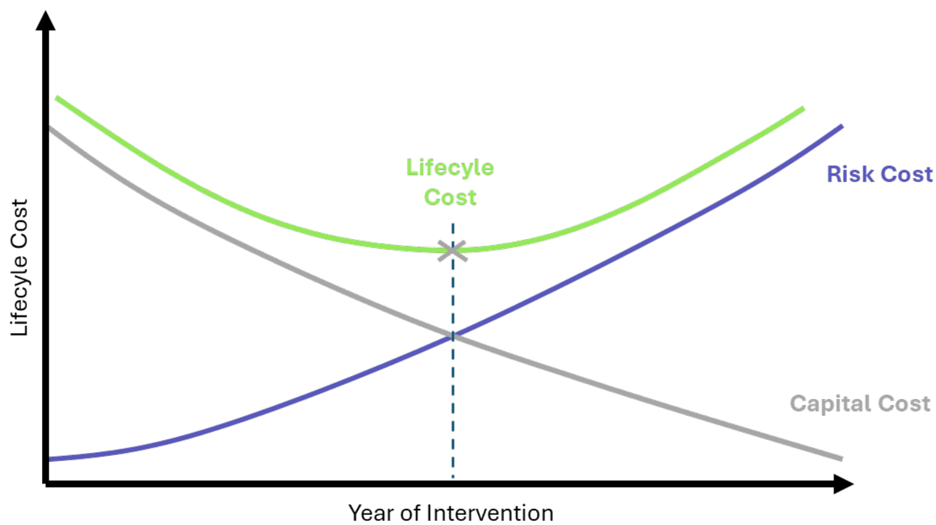
[6] https://www.engineeredintelligence.com.
[7] https://theiam.org/knowledge-library/iso-55000.

new practices and secures the necessary data inputs. However, as the use of the tool matures, additional analytical use cases can be expected to be adopted.

Q. How are all these different options or different projects compared in practice?

A. The core principle of risk-based asset management is minimization of asset lifecycle economic costs, i.e., the total of all expenditures arising from operating a given asset from its installation to decommissioning. Lifecycle cost minimization involves performing asset intervention (replacement, upgrade, or refurbishment) as closely as practical to the point in an asset's life where its annualized Capital Costs (which decline over time) equal its annualized Risk Costs (which increase over time) as shown in Figure 1 below.

Figure 1



In other words, as an asset's value in service is gradually consumed as it performs its assigned tasks, its remaining economic value decreases (just like with depreciation used for accounting purposes). At the same time, as an asset ages, physically deteriorates, or begins approaching the number of operations it was designed to perform safely and efficiently (like with circuit breakers, reclosers, or battery storage units), it is more likely to fail in service. Depending on the cost consequences of this failure in service, which is a function of multiple factors I discuss below, it may be more efficient to "intervene" regarding this asset by replacing, refurbishing, or otherwise modifying it before an event occurs that would have a negative impact on service to customers.

Importantly, and as I discuss more below, this does not mean that every asset has to be replaced before it fails, as for many types of assets and their modes of failure, the cost consequences of their failure in service are such that it is more efficient to replace them in a reactive manner, i.e., after they fail. On the other hand, as I explain further below, some assets are so critical to safe and reliable utility service that they should be replaced before their expected failure.

Q. What are good examples of assets that are worth replacing before they fail and those that are not?

A. Two types of transformers help highlight the differences between assets worth replacing before they fail and those that are not: (1) individual pole-top transformers, which in Liberty's case typically support between two and four residential customers, and (2) substation transformers that support multiple feeders and hundreds or thousands of customers that they serve. Pole-top transformers are relatively inexpensive, are standard in their design and capacity increments, and can be replaced in a relatively short period of time by a small line crew, causing a relatively short interruption that affects a small number of customers. While aged pole-top transformers are often replaced proactively in the course of larger pole line renewal, upgrade, or system hardening jobs, it would be inefficient for Liberty to replace individual transformers before they fail.

Conversely, substation transformers cost millions of dollars, require the manufacturer to customize the units' high- and low-side voltage, take days (if not weeks) to replace, and require a lead time as long as four years based on the latest industry information. When it comes to this asset class, proactive renewal is paramount. However, it is equally important to ensure that this replacement does not happen too early, i.e., when the unit's remaining Capital Cost is higher than its Risk Cost.

Q. How does this all translate into a Cost-Benefit Analysis framework?

A. In conducting the cost-benefit analysis of preventing future asset failures through replacement or other modes of intervention, the cost of asset intervention at a given time is treated as a Cost component (or cash outflow) in the Discounted Cashflow Analysis, while the cost of potential failure that asset intervention avoids is treated as a Benefit (or cash inflow). Recognizing that future asset failure (and its ensuing cost) is not certain, comparing the potential cost of failure with the certain cost of replacement requires adjusting the cost of failure (expressed in dollars) by the likelihood (or probability) of that failure occurring in a given year (expressed as a percentage). The adjustment of an estimated cost impact of failure by the estimated probability of failure yields the Risk Cost:

Event Risk Cost ($) = Probability of an Event (%) × Impact of an Event ($)

To account for the opportunity cost of capital and the fact that both costs and failure probability change over time, the cost-benefit analysis involves an adjustment to account for the time value of money using the Weighted Average Cost of Capital ("WACC") embedded in a utility's rates. To account for the value already derived from operating the existing asset, the analysis annualizes its lifetime capital costs and incorporates only the value remaining at the time of a hypothetical intervention.

In the end, the fundamental idea behind CBAT's risk-based asset intervention analysis entails a Net Present Value ("NPV") evaluation of the costs of continued operation of an asset, and the benefits of replacing that asset to avoid the risk-adjusted costs consequences of its failure in a given year. Individual assets that undergo this analysis can be grouped into projects of geographically and electrically adjacent assets using a variety of configurable rules and tools, which enables evaluation of larger projects, and comparison of projects among themselves. Since the final unit of analysis is presented as an NPV dollar value, it is possible to compare individual projects' relative value propositions across different asset portfolios based on these outputs and the underlying planning assumptions.

Q. What inputs are required to enable this analysis?

A. Among the key inputs that enable the CBAT software to perform its analysis are data sources that help capture the status quo of the existing system, information that helps estimate the probability of their failure, malfunction, or other negative performance outcomes over time, and the economic impact of these outcomes. Specifically, as Liberty continues configuring the CBAT software, it is exploring the availability and relative value of the following data points:

- Information on current state of assets where investments are contemplated:
    - Physical condition of equipment (visible wear and tear, operating counts for mechanical devices like breakers and reclosers, results of insulating oil analysis for transformers, etc.);
    - Equipment demographic data (age, model, material, location);
    - Manner and extent of utilization (average loading, peak capacity, etc.).
- Data on the likelihood (probability) of events an investment seeks to prevent (e.g., outages) or facilitate (e.g., new customer demand requiring transformer upgrades materializing in year x versus year x+1):

- Information on past failures (how, when, where) – based on the asset's own or comparable assets' operations depending on data availability;
- Past records of DER connection volumes and expected future demand based on customer surveys or other available information;
- Past trends of actualized demand growth and known future development plans that may influence availability of transformer capacity.

- Data on impact (value gains or losses) of events that investments seek to prevent or facilitate:
  - Costs of potential repairs and damages if assets fail unexpectedly (direct utility costs like truck rolls, overtime, and lost revenues);
  - Costs sustained by customers due to service interruptions (Customer Interruption Costs);
  - Safety costs of potential injuries to employees or public based on actuarial estimates or past precedents;
  - Environmental costs estimates of damage sustained due to asset failure or malfunction (e.g., oil leaks);
  - Presence of redundancies and other capabilities that can mitigate the probability of interruptions.

Q. How are all these data points integrated to represent the actual electrical system?

A. This is done by securely embedding into the software a copy of the Company's electrical connectivity model contained in GIS systems to enable the individual asset age and condition values to be attached to specific asset hierarchies, relationships between individual feeders, laterals, and their subcomponents, down to individual protective regions separated by fuses. Using unique Asset IDs from the Company's

GIS system, the available asset demographic and health records are matched with specific geospatial locations (see Figure 2).

Figure 1: Health Index-Based View of a Section of Empire's Distribution System

The final critical piece of information captured in this step for each asset is its location relative to protective regions (customer connections located on the same feeder within the boundaries of the same protective devices like fuses) and the number and classes of customers that reside on each feeder. These connectivity relationships that reflect the actual system configuration are a key factor in CBAT's ability to establish the criticality of a specific asset relative to other system components. The higher the criticality of an asset, the higher the relative impact of its failure would be on the system, other things being equal.

Supplementing the age, health, and connectivity data are inputs related to asset intervention costs, such as labor, materials, equipment, and vehicle costs. Other notable cost factors include adders for emergency or overtime asset replacement and outage restoration work, which enables the model to differentiate between planned work and emergency work that takes place when assets fail in service.

Q. Does the Company have detailed costs for these individual system components?

A. Not yet, but work is ongoing so that the equipment intervention cost data captured in the model is based on realistic and consistently applied estimates that are appropriately demographically adjusted to capture the remaining value of assets currently in service. Importantly, because the Company will use the model to evaluate projects at a portfolio level, i.e., relative to other potential projects, the cost information in the model will not be as precise as the highly location-specific cost estimates developed in the detailed design stage of each project.

Q. What about asset age, condition, and demographics data?

A. Data availability varies significantly from one transmission or distribution asset class to another, but the Company has made significant strides over the last decade to capture and systematize a large amount of system condition information for the highest-value assets, including poles and underground cable. While material data gaps remain, the ongoing CBAT project implementation has enabled the Company to confirm their scope and magnitude, which will help fill the data gaps over time. Nonetheless, based on our current assessment of the availability and quality of asset data, we anticipate producing the first batches of business case analyses using this methodology in conjunction with the Company's 2025 PISA filing.

Q. What about the probability of failures? Where does that data come from?

A. A failure probability curve for each asset class over time is defined by a Weibull probability distribution curve, the shape and scale parameters of which are determined in software configuration workshops that take place during deployment. A starting point is an asset class failure curve that the vendor provided based on their prior engagements and industry research. This information is then reviewed by local subject matter experts and augmented as appropriate based on locally available information. The software package also has a machine learning-supported module that helps further customize failure curve shape and scale parameters for each asset class over time based on the field failure data collected over time.

Q. How is failure probability calculated for each individual asset?

A. From a baseline failure curve applied to each asset class, individual asset failure probability values are automatically configured, based on their age and available condition information, which is organized in the form of Health Indexes. Health Indexes integrate the results of multiple numerical asset condition parameters that are available, such as power transformer Dissolved Gas Analysis test results, wood pole remaining strength assessments, underground cable testing results, and others. The function of asset condition data is to augment the failure probability curves that are initially based on age data only. Just like two 50-year-old individuals may have different life expectancies depending on their habits, diets, exercise routines, and prior health history, two pieces of equipment of the same age will have varying failure probabilities depending on the extent of damage they sustained due to natural phenomena, load cycling, number of field operations, and other parameters. The presence of condition data either accelerates or rolls back individual assets' "effective age" in the model, thus adjusting their calculated failure probability.

Q. Can you share a practical example of what factors make up a Health Index?

A. Yes. Figure 3 below showcases the current Health Index parameters that will be used to develop and track substation power transformer Health Indexes over time.

Figure 2: Working Version of Empire's Power Transformer Health Index Algorithm

Asset Health Index Breakdown

Degradation Factors

Degradation Factor	Data Available	Data Valid	Weight	Score	Final Score
Age of Transformer	✓	✓	3	0	0 / 12
Visual Inspection	✓	✓	5	4	20 / 20
Main Tank Dissolved Gas Analysis	✓	✓	5	3	15 / 20
Main Tank Oil Quality	✓	✓	3	0	0 / 12
Insulation Power Factor	✓	✓	4	4	16 / 16

Data Availability Index = 100%	20/20
Data Validity Index = 100%	20/20
Health Index = 63.8%	51/80

As the figure shows, there are currently five parameters that range from empirical measurement tests and visual inspection results that are translated into discrete numerical categories. The relative weighting of parameters is determined in pre-implementation workshops based on reference to industry publications (e.g. IEEE work papers), vendor recommendations, and judgment of local experts.

Q. Has additional field condition data been collected to populate this analysis?

A. No, we are using data that is currently available through the Company's existing maintenance and inspection programs. Historically, this inspection data was primarily used to identify the most immediate candidates for intervention based on readings that indicated impending failure or merited further investigation in the near term. That left a lot of data pertaining to equipment that performed in the normal ranges or exhibited modest or non-critical signs of deterioration to be set aside. With the ongoing adoption of a risk-based approach to T&D asset management, we can use all this available data to provide increased stratification across all equipment where data is available. This not only extracts additional value from the inspection costs previously incurred, but it will also help the Company develop more precise long-term capital expenditure forecasts and conduct more meaningful scenario analysis work.

As the Company moves from piloting this tool (and the analytical framework underlying it) to its full implementation in day-to-day planning operations, we expect to gradually investigate opportunities to augment and expand asset data availability to further enhance the rigor of this analysis.

Q. Will the CBAT analysis you describe use VOLL study outputs in calculating customer impacts?

A. Yes. By using customer interruption costs, the model will be able to calculate the full value of outage cost avoidance along with a calculation of direct utility cost avoidance. As I describe in the section dedicated to the VOLL study, customer interruption costs vary by customer class. Because different combinations of customers take service from each feeder, forecasted failures of equipment located in different parts of the system will have a different Risk Cost impact, resulting in different project NPVs, all other things being equal.

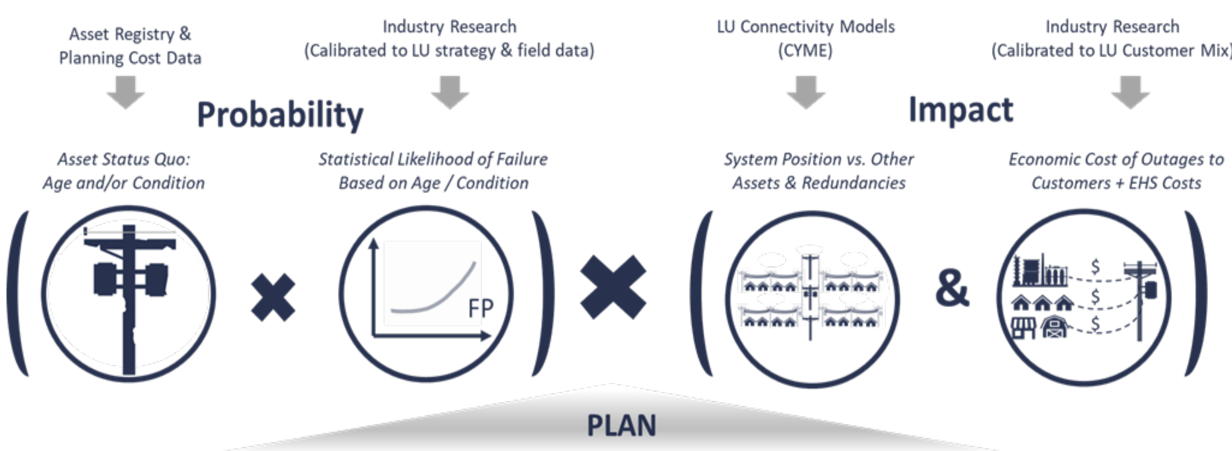
Q. Does this mean that the CBAT will not be functional until the VOLL study is completed sometime in 2025?

A. No. While we look forward to getting Missouri-specific CIC data for the CBAT model, the Company will be able to use CBAT with the first-generation CIC data available from the DOE's ICE calculator I discussed above. This data is adequate for stress testing and further augmenting and customizing CBAT analysis to reflect the Company's local system conditions and planning philosophy.

Q. How do all of the elements combine to produce a framework that has cost-benefit analysis at its basis?

A. Figure 4 below showcases how all the key inputs of risk-based planning interact at the foundational level to help planners evaluate the relative value proposition of different T&D capital projects. There are many more nuances, such as asset failure modes (e.g., inspection-based, normal, and catastrophic), the actuarial costs of safety or environmental incidents that certain asset failures can occupy, and many others. Each of these components introduces additional opportunities to increase the overall robustness and sophistication of the planning process as the model is set up, configured, and increasingly incorporated into the planning processes over the next several years.

Figure 3: Interaction of Risk-Based Planning Inputs in Performance of T&D Project Cost Benefit Analysis



Q. Is Liberty moving toward allowing computer models to dictate the Company's decisions about asset planning and project prioritization?

A. Absolutely not. As the Company emphasized during its two meetings with Staff and OPC, the purpose of implementing these analytical models and tools is to augment, not supplant, expert judgment, experience, and analysis. By enabling automated assessment of the candidate projects in the capital program, as well as periodic reassessment of the assumptions underlying the model as projects are completed and more field data is available, the CBAT will give the Company "objectivity at scale," meaning that it will help ensure that all projects undergo an initial rigorous comparative computational analysis based on a set of consistently applied criteria to identify the highest-value opportunities for asset intervention. More specifically, the automated CBAT's workflows will help:

- Bring consistency to the evaluation process;
- Counter inherent evaluator bias;
- Enable efficient high-volume processing of candidate projects;
- Simplify comparison across different investment categories;
- Enhance planning assumption-to-outcome feedback loops; and
- Alert engineers of potential anomalies in planning assumptions.

The results of this high-volume computational analysis would then be subjected to review and augmentation based on the judgment of the Company's professional planners and engineers, who will have more time to spend on higher-value tasks.

It is critical to emphasize that CBA frameworks' and risk-based planning tools' efficiently and objectively derived predictions are meant to inform and enhance expert engineering judgment, not to replace or trump it. By unburdening experts from a large volume of manual tasks, CBAT will allow those experts to dedicate more time to verifying, correcting, or otherwise modifying the model-derived insights and further enhancing the tool and the processes it supports over time.

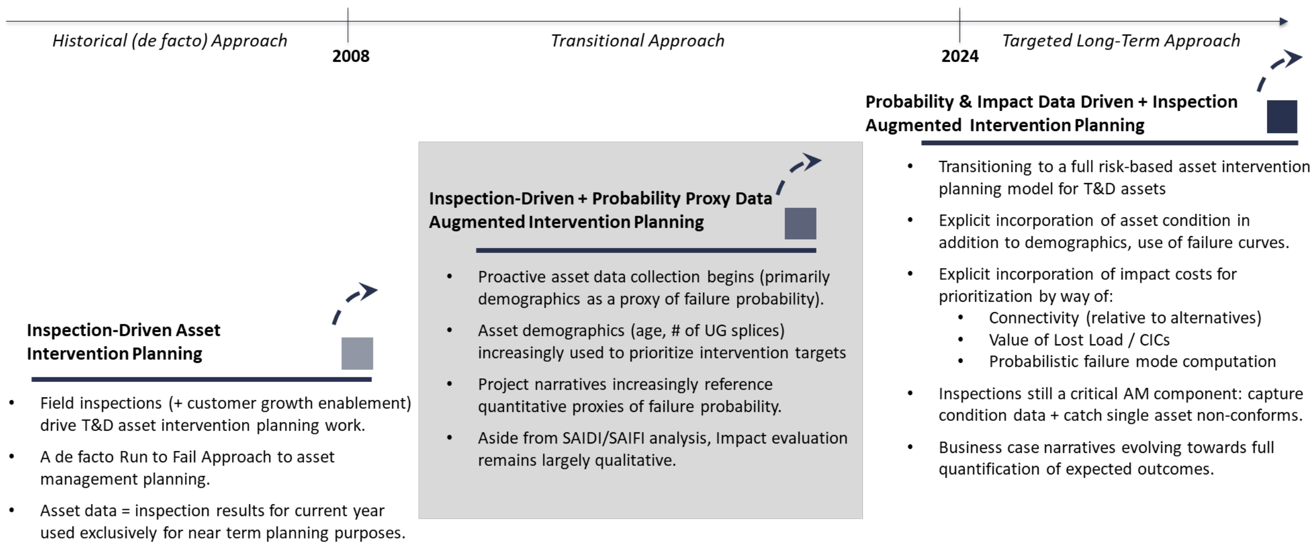
Q. What is the current status of the project to implement the CBAT?

A. Since the beginning of this project, the Company has made significant strides toward modernizing our planning work, making it more data-driven and efficient. The CBAT is now installed, configuration internal workshops and training are underway, and the Company is working toward presenting an initial batch of CBAT-supported CBA documents in the 2025 PISA filing. Importantly, installation and initial customization are only first steps on what we expect to be a multi-year journey, during which the Company's utilization of and reliance on the CBAT will evolve. As noted above, we expect to share the first batch of project CBAs in the 2025 PISA filing. Though much work remains, we look forward to deriving significant operational and strategic value from this project.

Q. How does Liberty's CBAT effort fit into its longstanding efforts to enhance its approach to project value analysis?

A. For more than 15 years, the Company has been methodically executing on multiple intervention planning and analytics modernization tasks. Figure 5 below showcases the phases of ongoing evolution of the Company's approach to project value analysis, including work recently undertaken in response to the Stipulation commitment.

Figure 4: Evolution of T&D Project Value Analysis at Empire



As Figure 5 shows, the Company has long made proactive and systematic investments in collecting asset condition data and consolidating demographic records for overhead, station, and underground equipment, developed advanced GIS system capabilities, and greatly enhanced its reliability planning tools and processes. These proactive enhancements (many of which continue today) have already contributed to a substantial improvement in system reliability, efficiency, and public safety, and they have also helped form a foundation for further advancements in evidence-based system planning.

V. UPDATE ON THE TRANSPORTATION ELECTRIFICATION PILOT PROGRAM ("TEPP")

Q. Please briefly summarize the main tenets of the TEPP.

A. The Company's TEPP consists of five main components:

- *The Residential Smart Charge Program* is a subscription electric vehicle ("EV") charging service that allows customers to finance the cost of a residential charger purchase and installation on their bills while getting access to a high-differential time of use ("TOU") rate schedule applied specifically to

EV consumption, i.e., netted out of the overall household consumption, which is billed at rates of an applicable residential tariff. Customers are eligible for a $200 rebate to cover the eligible costs of electrical panel upgrades and have an option of pre-paying for the charger the Company supplies, thus avoiding the financing charge they would otherwise pay.

- *The Ready Charge Pilot Program* is a program that deploys Company-owned and operated Level 2 ("L2") and Direct Current Fast Chargers ("DCFC") at publicly accessible commercial host sites. Program participants (businesses or municipal organizations that own or lease the charging sites) pay a monthly participation fee to recover the cost of infrastructure deployment, financing, and operating costs. Energy consumption is charged on a dedicated TOU rate schedule with different rates for L2 and DCFC charges. Site hosts have an option of either covering the cost of charging for EV drivers (using the assets as a means of attracting them to adjacent businesses) or passing on the cost directly to drivers. The Ready Charge Program's budget is separated into four milestone-based tiers. To access each subsequent tier of funding, a material portion of the Company's existing public charging stations must demonstrate a consumption growth rate consistent with originally agreed thresholds. As milestones for subsequent tranches are met, the Company would advertise the opportunity in an RFP-like manner to potential site hosts. Each funding tranche following the initial one requires an up-front capital contribution from the site host.
- *The Commercial Electrification Pilot Program* is similar to the Residential Program, but it instead deploys Liberty-owned and operated EV charging

infrastructure for non-public use by commercial fleets and employees of participant businesses.

- *The School Bus Pilot Program* provides charging infrastructure and TOU electricity consumption price schedules to support the operation of electric school buses at public school districts. The program deploys Liberty-owned and operated electric vehicle charging infrastructure. Schools must provide a proof of purchase of an electric bus to qualify for the program.
- *The Non-Road Electrification Pilot Program* provides rebates to encourage adoption of qualifying electric technologies that would otherwise be powered by gasoline or diesel. Qualifying electric technologies include electric forklifts of qualifying tonnage, electric-standby truck refrigeration units, and truck stop electrification equipment to power driver cabin appliances.

The Commission-approved stipulation concerning the TEPP ("TEPP Stipulation") approved dedicated tariffs for each of the above-noted programs.[8] The TEPP Stipulation also approved maximum capital and operating expenditure thresholds for each of the programs, along with a program administration budget. The TEPP also stipulates the maximum number of participants for each program facet. Transition provisions are also in place to specify how the program and the assets it deploys would be wound down at its conclusion across several potential scenarios.

Q. How will the Company recover the capital and O&M costs of the TEPP program, including the regulated return component where it is allowed?

A. The Company is tracking all revenues and expenditures on a program-by-program basis in a system of deferral accounts to be addressed in a future proceeding after the

[8] ET-2020-0390, Order Approving Stipulation and Agreement, January 19, 2022.

program's five-year pilot term has concluded. The Company is not seeking TEPP cost recovery of any kind in this proceeding.

Q. How would you characterize the TEPP program's track record since its launch in the fall of 2022?

A. A little more than a year-and-a-half since its formal launch, customer enrollment in the TEPP program has been modest. Nonetheless, the scope and nature of insights that the pilot has provided have been encouraging and instructive in important ways.

Q. How many participants enrolled in the program?

A. As of September 2024, the residential program had 39 participants out of the maximum 500 spots. The Ready Charge public charging program has allocated all available Tranche 1 funding across a total of eight L2 and one DCFC chargers to three site hosts located in Branson, Ozark, and Neosho. This helped the Company expand the availability of public EV charging infrastructure across its service territory, closing some notable public charging (and especially fast charging) geographic availability gaps that existed prior to the program's launch. One school has enrolled in the School Bus Program after being awarded two buses through the Environmental Protection Agency's ("EPA") Clean School Bus Program grant. They were one of only 25 schools in the state to receive the grant. Five other schools submitted grant applications for the second tranche of the same program, however none were selected for an award, pending any potential cancellations or refusals of awardees that could result in later offers to those whose applications were not selected. Despite some initial interest, there are no Commercial Electrification Pilot Program participants, which is largely a function of the program's restrictions on the minimum number of chargers. Finally, to date we have had no expenditures in the Non-Road Program rebates program.

Q. Did the Company anticipate greater demand for the TEPP program when it was first conceived and submitted to the Commission for review and approval?

A. Yes. We did not set any firm expectations, although the upward consumption trend across the public charging stations that Liberty had in place before the TEPP program's launch gave us grounds to expect continued growth across all types of EV charging segments. We were correct in our expectations of continued EV growth, although we expected the adoption pace to be faster. We attribute this discrepancy largely to the changes in the broader economy. When the Commission approved the TEPP settlement, the Federal Reserve's overnight target rate range was 0.00%-0.25%, whereas today the range stands at 4.75%-5.00%. As the cost of borrowing increased to counteract the pace of inflation, customer decisions regarding their discretionary spending, such as purchasing a new vehicle, were likely affected.

In addition, the program's launch coincided with continued supply chain constraints experienced across the EV industry since the COVID-19 pandemic. These constraints affected both customers' purchase decisions and the Company's ability to negotiate with charging equipment suppliers. While these constraints have significantly abated since the time of the program's launch, the rising costs of capital and the significant inflation that has only recently started to subside created conditions that are less than ideal for major purchase decisions, both for individuals and businesses.

Cost is certainly a factor in purchasing electric school buses. Because the School Bus Program requires applicants to provide the Company with the applicant's bus purchase documents, enrollment levels in this program were naturally affected by the timing and results of the EPA's electric bus grant program. As many as seven school boards in our Missouri service territory completed grant applications for the federal school bus grant programs in the first around, and another five applied in the second round. While to date this resulted in only one award in our service territory, we will continue supporting future school bus electrification plans in our service territory.

Finally, participation in some of the programs, most notably residential and commercial, has been affected by tariff provisions that have limited the Company's ability to enroll interested customers. For example, the minimum number of chargers for entry into the commercial program is three, which equals six charging ports. The prospective customers who inquired about the program informed us that their fleet electrification needs were more modest than the tariffed minimum. Similarly, a number of customers interested in the residential program were unable to enroll because they already owned chargers, which was not compatible with the program rules.

Q. Please describe the volumes of applications and inquiries that the Company has received since the TEPP program's launch.

A. Table 1 summarizes the volume of formal applications and the installation queue status as of September 17, 2024.

Table 1: TEPP Application and Queue Volumes as of September 17, 2024

Program	Completed Applications	Charger Units Installed	Installation Queue	Withdrawn from Queue / Program
Residential	70	39	11	20
Ready Charge	3	9	0	0
Commercial	3	0	0	3
School Bus	1	2	0	0
Non-Road Rebate	0	0	0	0

In addition to formal completed applications, TEPP program staff have handled an average of 50 customer inquiries per week since the program's launch. Requests range from questions about the program, EV technology, or anticipated savings to highly situation-specific requests to clarify the program rules, advice on electrical installation process steps, support in equipment troubleshooting or vendor contact, or requests for help with completing grant applications for prerequisite equipment like school buses. Not captured in the table above are significant numbers of applications that have been started but abandoned at some stage. While the Company's TEPP team members attempted to follow up with prospective customers in all such instances, application completion ultimately requires a number of pre-requisites, obtainment of which is beyond the Company's control.

Q. What have been the reasons for applicants withdrawing from the installation queue or the program overall?

A. In the context of the residential program, the most prevalent reason for queue withdrawal (18 out of 20 total withdrawals) has been customer ownership of pre-existing home charging equipment, which under the current tariff does not qualify for program participation. The single instance of program withdrawal after the installation was completed took place was due to the customer moving outside the Company's service territory.

Prospective customer withdrawals from the commercial program resulted from customers realizing that the minimum number of charger installations prescribed by the tariff was in excess of the number of fleet vehicles they sought to electrify at the time. As with the residential program, not listed are a number of additional serious inquiries or applications abandoned before completion from customers who either did not follow through on their plans to purchase fleet EVs or learned of minimum installation requirements or other program rules that did not fit their plans.

Q. Did the Company check whether the residential customers that chose to exit the program queue subsequently switched to Time Choice Plus rate class that also offers significant on-peak versus off-peak price differentials?

A. We followed up on that after Staff suggested it during a recent TEPP Program check-in meeting. At the time, none of the customers had made the switch (and none has switched since then). We have since taken steps to inform them of this opportunity.

Q. Please describe the key operational insights the Company has gleaned from the TEPP program to date.

A. Perhaps the most important insight is how helpful the Company can be to customers in navigating a confusing and evolving EV-related product marketplace. The marketplace for both charger and EV manufacturing remains nascent, with a multitude of vendors competing on product and service offerings that are still maturing and have varying degrees of quality, availability, and customer service support. Employees supporting the TEPP program have encountered a variety of challenges in working with vendors, including:

- Positions taken during supply contract negotiations on customer data ownership that the Company did not see as being in the best interest of its customers;
- Equipment vendors shutting down operations with no prior notice, leaving customers who purchased their equipment with no support or clarity as to the continuity of basic services or prepaid warranties.
- Vendor software upgrades occurring with little or no prior notice, which at times resulted in changes that temporarily affected data collection;
- Difficulties obtaining timely responses from customer service, shipping, billing, or legal departments of prospective or current vendors; and

- Charger and vehicle equipment compatibility issues unforeseen by manufacturers of either technology, occurring most notably in the context of the School Bus Program.

While the Company appreciates ongoing support and collaboration from its vendor partners, the examples of issues described above are indicative of a rapidly evolving marketplace that creates challenges in meeting or anticipating all customer needs on a consistent basis. Given this stage of a broader EV charging marketplace, the Company is convinced that having program team members dedicated to helping new and prospective customers navigate the challenges that arise from time to time in dealing with new equipment or its implications on their total consumption is an important investment in facilitating the EV transition. I describe a recent and compelling case study that supports our conviction below.

Whether educating customers about Time of Use intervals, coordinating required electrical installation or inspection work on their behalf, or liaising on their behalf with equipment vendors, TEPP personnel are helping Liberty ensure that customers are informed and supported as they make significant investments that affect their degree of reliance on the electric grid. Because TOU price differentials inherent in the program incentivize customers to charge off-peak, the program is helping to optimize usage of the existing electrical system. In short, and notwithstanding the challenges that we experience, the program is working as expected in terms of customer empowerment and support.

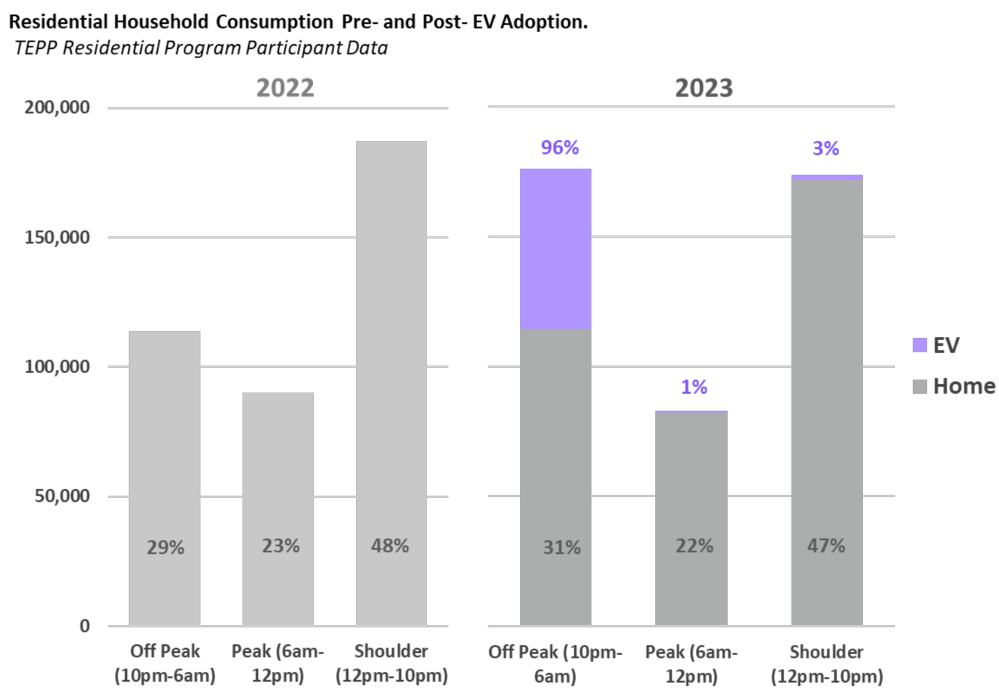
Q. Across the issues described above, what has been the single largest challenge in administering the pilot program thus far?

A. The Company recently learned that ENEL X Way USA ("ENEL"), the vendor of JuiceBox EV chargers and software deployed in the TEPP's residential segment, decided to close its operations in North America as of October 11, 2024. The vendor's initial statement suggested that while customers could continue using the hardware to charge their vehicles, the software and networking features that enabled customers and the Company to remotely access and analyze the charging information would no longer be available. This was and remains a significant concern, since Liberty relies on electronically accessible charger consumption data to bill customers and perform multiple analytical functions underlying the pilot. While the latest information suggests that ENEL's software will continue to be operational for a longer timeframe than originally anticipated, Liberty is examining all possible courses of action to minimize disruption to customers or compromise the pilot objectives. We are in regular contact with Staff, OPC, and the affected customers, and we are confident in our ability to attain a positive resolution.

Q. Has the Company examined the manner or extent to which adding EVs changes residential customers' consumption patterns and volumes?

A. Yes. As shown in Figure 6, our data suggests that TEPP residential customers have been diligent in following the TOU schedule. Approximately 96% of charging took place during off-peak hours, with three percent occurring in the shoulder time period. When the Company conducted a survey of residential program participants in late 2023, all respondents stated that time-variant rates influenced when they charge their EVs to a "significant extent."

Figure 5: RCCP Participant Household Consumption Pre- and Post-EV Adoption

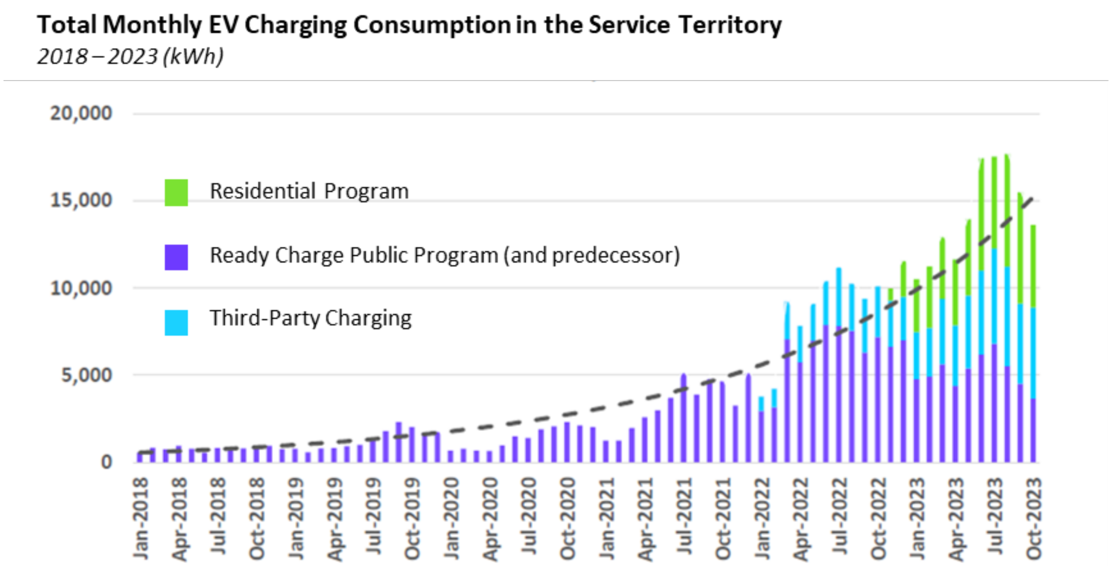


As the above figure suggests, while increasing overall consumption levels, EV adoption did not materially change the manner in which the households in question consumed energy across a 24-hour period. On a total kWh basis, EV consumption represented 13% of the examined households' combined consumption in 2023, which helped offset the 5% reduction in non-EV household consumption relative to 2022 that was attributable to milder weather. To get a sense of the magnitude of charging taking place today through the Company's residential program, it is worth considering that in January 2024 the total EV consumption by participants was equivalent to 161 full charges for a Tesla 3 rear-wheel drive vehicle, which in turn amounts to about 43,900 miles driven or 1.8 times around the globe by the circumference of the equator.

Q. Looking beyond the residential program, does the Company have a sense of total EV consumption over time across its service territory?

A. Yes. See Figure 7 below:

Figure 6: Energy Consumed Monthly for EV Charging: 2018-2023



Although we are certain that this graphic, inclusive of the Company's test year, does not capture all of the EV consumption taking place in our service territory, the graphic represents a robust growth trend, with average monthly EV consumption increasing by 6.5 times over the period captured on the graph. As indicated by the graph, aside from the chargers installed by the Company, a material portion of growth has come from public chargers installed by other entities, including Tesla chargers (which after recent standard modifications will soon be available to most EV makes), as well as charging infrastructure being installed in car dealerships, gas stations, and big box stores, among others. In total, there are now 86 publicly accessible charging ports in the Company's service territory, 36 of which are third-party installations. Following the additions of Branson, Neosho, and Ozark Phase 1 Ready Charge installations, the Company has eliminated "charging desert" areas, with the addition of a DC fast charging installation being of particular importance for travelers that pass through our service territory on longer trips.

Q. Has the consumption across existing public chargers increased sufficiently to access the second tranche of Ready Charge funding as per the TEPP Stipulation?[9]

A. No. The Stipulation provides that total consumption must increase by at least 25% across at least 60% of public chargers over the most recent six months of usage to access the second tranche of the program. Though there are multiple locations where the consumption growth threshold has been consistently exceeded, this is not yet the case across 60% of the public chargers the Company controls across its territory.

Q. Is there now a sufficient number of public charging installations across the Company's service territory?

A. The situation has greatly improved both in terms of the number and types of chargers in the more densely populated areas. In the past, drivers passing through our territory might have resorted to charging their vehicles through NEMA plugs at various RV parks due to the lack of nearby infrastructure, which is neither efficient nor consistent with their intended use. Today, the Company believes there are no longer any major charging gaps on main transportation corridors in the vicinity of larger municipalities that it serves. This is not, however, the case in the more rural or outlying areas, where the Company believes strategically placed public charger equipment additions would be beneficial.

Beyond having at least some public EV charging facilities in sufficient geographical proximity to eliminate charging deserts, the demand for public EV charging, and therefore the sufficiency of EV charging stations and ports, appears to be

[9] ET-2020-0390, Order Approving Stipulation and Agreement, pp. 14-16, January 19, 2022.

somewhat seasonal. Figure 7 above reveals a clear seasonal pattern to public charging volumes, where consumption noticeably dips in the winter months but invariably rebounds as the warmer summer weather returns. The Company attributes this pattern to the influx of out-of-area drivers visiting summer recreational facilities in the Ozark and Branson areas. Thus, the question of whether there is enough public charging infrastructure in Liberty's service territory is in large part a question of how quickly EV adoption grows outside of our service territory. The Company is closely monitoring the situation by analyzing the utilization rates of public charging ports across the major routes on a regular basis.

Q. Has the Company polled EV drivers who reside in its service territory about their thoughts on public charging?

A. Yes. The previously mentioned TEPP program customer survey conducted in late 2023 asked respondents two questions related to public charging. The first question asked respondents about how often they worried about their EVs' range when using them for regular trips such as commuting or errands. The second question asked respondents whether their confidence in their EVs' range would improve if there were more public charging stations along the routes they travelled. In the case of the first question, 83% of respondents stated that they rarely or almost never worry about their EVs' range when performing their regular weekly trips. However, when asked whether their confidence in their EVs' range would improve if public charging was more readily available in their areas, 56% gave affirmative answers, adding there are either insufficient public charging options or they worry the options that exist today would become insufficient as more EVs hit the roads.

Q. Does Liberty monitor the uptime of their public charging infrastructure?

A. Yes. We are aware that malfunctioning public chargers are a major source of frustration for EV drivers across the country. Over the last year, the total uptime (meaning the time the chargers are functioning and available for use) of Company-controlled public chargers in our service territory has been 99%. TEPP team members regularly monitor the uptime and work with vendors to return chargers to service as soon as possible while also posting notices of charger outages on public forums.

Q. The TEPP Stipulation includes a list of potential technical pilot areas the Company planned to investigate subject to various conditions materializing which would make them warranted or cost-effective.[10] Has the Company made progress in any of these areas?

A. Yes. At the time of working with parties to the TEPP Stipulation, we outlined a comprehensive list of potential areas where we could draw program implementation insights irrespective of how the program uptake took shape. Aside from customer service, economics, demographics-related metrics mentioned above, and several other areas, we have zeroed in on two specific technical matters: charging equipment's suitability for customer billing of residential EV consumption and the implications of EV growth on overhead and underground line transformer capacity across the service territory.

[10] ET-2020-0390, Order Approving Stipulation and Agreement, pp. 14-16, January 19, 2022.

Q. Describe the Company's work to explore the suitability of using home EV chargers for the purposes of separately billing customers for their EV consumption.

A. A key distinguishing feature of the Company's residential program is that the EV consumption is billed on a separate rate schedule from the rest of the household consumption. To enable this, the Company proposed to use consumption recorded through the EV charger itself, which the Company can access online, rather than installing a second revenue-grade AMI meter to measure the kWh consumed through the charger. At the time of billing, consumption recorded through the charger is reconciled with the total kWh consumed by the household (as measured by the AMI meter) and the appropriate charges are applied. To explore empirically whether and to what extent the consumption recorded through chargers is consistent with that captured by revenue-grade AMI meters, the Company installed two dedicated residential chargers at one of its operations centers with AMI meters attached immediately upstream of each. This installation is pictured in Figure 8, and is used by the EVs in the Company's fleet.

Figure 7: Home charger accuracy exploration installation at Liberty's operations center in Joplin

By regularly comparing consumption records between chargers and the upstream AMI meters over time and various weather conditions and accounting for chargers' own power needs, the Company hopes to explore potential suitability of using home chargers for dedicated EV consumption measurement on a broader scale. For clarity, we are certainly not aiming for any definitive *empirical* insights as to the chargers' suitability for revenue-grade consumption measurement given our modest set-up. However, we believe that the *managerial* insights we will be able to collect in this manner will be instructive to the Company and other stakeholders as we jointly facilitate the growth of EVs across our service territory. For instance, while EV-specific rate classes may not become mainstream, the Company can foresee a scenario where it continues to rely on remote monitoring of EV charger consumption across its service territory for activities like load research (e.g., by encouraging customers to voluntarily share their EV consumption data). Therefore, a data-driven understanding of how consumption data captured through chargers compares to that recorded by AMI meters during various weather conditions can serve as a meaningful planning input.

Q. Describe the work to explore potential line transformer capacity limitations associated with EV charging.

A. It is a well-documented industry concern that increased proliferation of EVs, which would be expected to charge at home overnight, could accelerate the degradation of overhead and underground line transformer equipment, thus shortening their useful lives. This concern arises because these critical pieces of utility equipment do not contain dedicated cooling mechanisms that are present in larger substation transformers. Instead, line transformers are designed to cool overnight through a combination of lower ambient temperatures and reduced overnight customer load.

Potential concerns arise when multiple EVs are connected to the same line transformer and are charged simultaneously, thus eliminating or reducing the time that equipment can cool and accelerating the rate of winding insulation breakdown and accumulation of dissolved gases in the insulating oil, among other potential degradation factors. Although industry participants are investigating a number of potential solutions to address this issue, such as managed charging applications, the Company has begun its own investigation of the potential for this issue to become a future challenge in its service territory. Using GIS system data on the capacity of line transformers across its service territory and numbers of customers connected to each, AMI data of customer load profiles, and EV charging profiles of TEPP program participants and other known EV charging infrastructure installed on the grid, the Company has performed initial simulated system stress testing to determine the type and number of at-risk transformers, conditions under which the probability of accelerated transformer degradation would increase, and outlined potential mitigating measures.

Q. What has the Company's analysis suggested to date about the probability of accelerated degradation of line transformer equipment due to EV usage growth?

A. Aside from the low penetration of EVs to date, a factor that materially reduces the probability of systemic EV-driven premature line transformer degradation in the near-to-medium term is the low load density across the Company's service territory. By virtue of serving smaller municipalities and rural areas, there is a comparatively small average number of customers connected to Liberty's line transformers relative to more urban areas of the country. This means that although approximately 20% of the line transformer fleet could face a theoretical risk of overloading and useful life degradation if each connected customer adopted an electric vehicle, the current adoption pace suggests this is unlikely to become a systemic issue any time soon.

As EV penetration increases, one potential mitigation strategy involves updating standards to impose a limit on the number of customers connected per transformer of each rating. The Company will continue to monitor this issue over the remaining life of the TEPP program by continuing its current practice of mapping known customer EV installations in the GIS while enhancing the scope and precision of future stress testing exercises. As the Company gains additional experience with AMI data analysis, it may explore the costs of using AMI data to identify locations with EVs behind the meters based on their electrical signatures. This is the same approach the Company used recently to identify and address behind-the-meter solar installations that were not registered with the Company.

One area that warrants additional investigation is line conductor capacity, concerning which the Company regularly works to augment its asset records through data collection initiatives like the one that took place in the course of the VOPT study field work. As the Company augments its conductor rating asset records in the coming years and EV consumption grows to give us more data from different parts of the system, we expect to materially enhance our empirical understanding of the probability, impact, and technical logistics of scenarios where grid edge technology adoption can have a material bearing on the Company's asset management practices related to conventional utility equipment.

Q. Are there any other activity areas where the TEPP program is making a positive contribution in the broader realm of energy transition?

A. Yes, and that is in providing support for public sector and private entities' applications for a variety of available EV charging infrastructure grants. To date, TEPP program team members have helped 16 communities the Company serves evaluate the potential of their contemplated projects for the Charging and Fueling Infrastructure Discretionary Grant Program, three of which proceeded to full applications. Similarly, TEPP team members supported two applications for funding available through the

Volkswagen Environmental Mitigation Trust and worked with dozens of potential hosts who were contemplating the National Electric Vehicle Infrastructure formula grant applications.

Perhaps most notably, TEPP team members provided support to 63 schools in the Company's service territory in evaluating the potential for electric school bus acquisition through federal grants. Eight of these schools proceeded to submit full applications for federal funding to purchase electric school buses. Of these eight applicants, the Fair Play School District has been awarded a grant for two school buses. Given the administrative burden and technical nature of application research, evaluation of eligibility, and application preparation, the Company's TEPP team members play a key advisory role that simplifies and streamlines evaluation and pursuit of opportunities for a significant number of stakeholders to access public infrastructure funding.

Q. Is the Company proposing any TEPP program tariff amendments in this case?

A. Aside from the changes to electricity consumption costs and cost of capital parameters that will flow through the existing tariffs at the conclusion of this rate case (see the testimony of Company witness Timothy S. Lyons), we are not proposing any further amendments. While we have explored several potential changes ahead of this case internally and sought preliminary feedback from Staff and OPC, we ultimately determined that the existing tariff structure is sufficient to support the derivation of insights that we hoped to achieve over the program's duration.

Q. What should the Commission conclude regarding the status of the Company's TEPP program to date?

A. The Commission should conclude that the program is functioning as expected, providing valuable empirical insights across a variety of operating dimensions while helping the Company work with our early adopter customers to ensure that their charging practices facilitate sustainable and efficient long-term system utilization outcomes.

VI. THE GRIP PROGRAM APPLICATIONS UPDATE

Q. What is the GRIP Program?

A. The Grid Resilience and Innovation Partnerships ("GRIP") program is a federal infrastructure grant program administered by the U.S. Department of Energy ("DOE") and enabled by the 2021 Infrastructure Investment and Jobs Act ("IIJA"). The GRIP program provides funds for projects in three Topic Areas. Investor-owned utilities like Liberty can submit project applications for federal matching funds of up to 50% of project costs in two Topic Areas, with the third being reserved for states, local governments, and public utility commissions. The first Topic Area is Grid Resilience Grants, where applicants are encouraged to submit funding applications for projects that "reduce the likelihood and consequence of impacts to the electric grid due to extreme weather, wildfire, and natural disaster."[11] The second Topic Area is Smart Grid Grants, which seeks projects grounded in advanced technology solutions, including "new devices, materials, engineering designs, or software tools."[12] The DOE is

[11] GRIP Program Funding Opportunity Announcement (FOA) Document, p.9.
[12] *Ibid*., p 14.

currently evaluating the second tranche of project submissions, having announced the entities selected for award negotiations in the first tranche in October 2023.

Q. Has the Company applied for the GRIP grants?

A. Yes. In the GRIP program's first tranche, the Company submitted three Concept Papers according to the requirements of the initial stage of the grant selection process. Two of the project Concept Papers were submitted in the Grid Resilience Topic Area and one in the Smart Grid category. In the Smart Grid category, the Company proposed an initiative named "Project DA" to deploy Distribution Automation ("DA") equipment across its service territory while also renewing and upgrading its line and station infrastructure to support new DA functionalities.

In the Grid Resilience category, the Company submitted one distribution-focused and one transmission-focused project. The distribution-focused project was titled "Project MVF – Most Vulnerable Feeder ("MVF") Hardening, Supported by Crowd-Sourced Digital Asset Imagery Analytics." The project sought to rebuild, upgrade, or harden the most distant and sparsely populated parts of the system that showed signs of material deterioration. The sites would be selected with the help of a crowd-sourced power grid imagery analysis machine learning application, which the project also sought to develop. The transmission-focused project Concept Paper was titled "Ozark Line 39-0 Rebuild Project" and proposed a rebuild and uprating of one of the oldest transmission circuits in Liberty's system, which would enhance inter-area transfer capability between neighboring RTOs, increase transmission service reliability within Liberty's own territory, and reduce the risk of wildfires along the line's right-of-way, which passes through the Mark Twain National Forest.

Q. What was the DOE's feedback on the three Concept Papers?

A. The DOE encouraged all three of the Company's Concept Papers to proceed to the Full Application stage, where a substantially greater amount of technical and financial information was required, along with other materials, including environmental assessment scans, letters of support from local stakeholders, and a detailed Community Benefits Plan. To be considered complete, applications needed to be responsive to a comprehensive set of highly specific criteria regarding their alignment to the federal government's policy objectives in the areas of energy transition, local and national economic development, diversity, equity, and inclusion, disadvantaged communities support, and others. Considering that only about 50% of Concept Papers from across the United States were encouraged to proceed to the Full Application stage, DOE's encouraging the Company to advance all three of its Concept Papers to the Full Application indicated the Company had assembled a set of strong submissions that showcase its planning expertise.

Q. Did the Company pursue three full applications in the first Tranche?

A. No, we prioritized two distribution-focused applications, which we saw as being more consistent with the GRIP program's objectives and having coverage across both the Grid Resilience and Smart Grid Topic Areas. Moreover, based on the DOE guidance provided at the initial seminar after the Concept Paper results announcement, the Company understood that it could continue with the third encouraged Concept Paper in the program's second tranche and proceed directly to the Full Application stage.

Q. What were the results of the Full Application Stage?

A. In October 2023 the Company learned that its Smart Grid application ("Project DA") was selected for an award along with approximately 30 other projects from across the country. The Grid Resilience application ("Project MVF") was not selected for an award. Along with the Company's project, its affiliate Liberty Utilities (CalPeco Electric) LLC was also selected for an award in the Smart Grid category.

Q. Please provide additional details on Project DA selected for the grant award.

A. Project DA contemplates a significant digitalization of the Company's field operations by deploying approximately 300 auto-recloser devices equipped with the Fault Location, Isolation, and Restoration ("FLISR") technology. Auto-reclosers will be arranged in clusters located at the physical junctures of adjacent distribution trunk feeders, which will enable them to automatically restore power to portions of feeders affected by outages of a certain type by establishing an alternate power supply path from an adjacent feeder through pre-arranged automated sequences of opening and closing. To enable device-to-device communication and alert the Company when devices operate, the Company will also deploy field communications equipment in support of each cluster of auto-recloser devices.

Along with deployment of auto-reclosers, the project scope includes extensive pole renewal and conductor capacity rating upgrades in the vicinity of the auto-recloser installations when doing so is deemed necessary or beneficial based on the asset age, condition, or feeder loading analysis. Project plans also include capacity upgrades to several distribution substations to enhance their ability to temporarily absorb the load transferred from faulted feeders and enable future load growth more generally. Thus, in addition to substantially automating the Company's distribution system to enhance reliability, the project is also set to renew, reinforce, and expand the capacity of conventional line and station infrastructure that would be required absent the automation project.

Q. What specific benefits can the customers expect from Project DA's implementation?

A. The Company is targeting a 33% improvement in Customer Minutes of Interruption on the feeders that the project affects by the time the entire initiative is completed. In addition, the trunk feeder sectionalization, deployment of auto-reclosers, and capacity upgrades to over 30 miles of distribution line and up to three transformer substations will significantly enhance the system's operational flexibility and add resilience during high-wind and snowstorm events through deployment of new, higher-rated line infrastructure.

Q. Does any of the work in the scope of Project DA represent new technical approaches that the Company did not consider previously?

A. Not at all. Plans for each of the major project scope components, including DA devices, feeder renewal and hardening, and substation and feeder capacity upgrades, have been in place for some time and previously socialized through our PISA update reports and Integrated Resource Plans. The DOE award potential did create a unique opportunity to deploy DA equipment and other supporting upgrades across the Company's network at scale through a five-year "sprint" exercise. Deployment speed notwithstanding, the technical work underlying Project DA has been in the Company's plans for a long time.

It is worth noting that multiple parts of Project DA are a logical continuation to Operation Toughen Up that the Company has implemented over the last decade. Whereas Operation Toughen Up largely targeted sectionalization and renewal of equipment on the lateral lines emanating from the main trunk feeders, Project DA will largely target the trunk feeders themselves. This is a more logistically complex undertaking, which will also involve installation of more technologically sophisticated system operation equipment and is therefore more appropriately pursued once the "lower-hanging fruit" of lateral sectionalization has been accomplished to a significant degree. In the case of Project DA, the promise of a $47 million contribution by the federal government towards this project makes this undertaking that much more valuable for the Company's customers.

Q. Did the Company inform any of the Missouri regulatory stakeholders about its GRIP program application plans or the scopes of projects?

A. Yes. The Company provided a comprehensive overview presentation on all three project applications described above in the docket AW-2023-0156 in April 2023 and provided another written update in October 2023. Before submitting the applications, the Company also reached out to OPC for letters of support for the two full applications. OPC provided these letters, which we included into the grant submission package.

Q. What is the anticipated timeline of Project DA's execution?

A. Consistent with GRIP program rules, Liberty formulated the project to be completed over a five-year timeframe. Because the project plan is composed of installation and upgrade work across multiple discrete sites, the project is expected to come into service gradually as individual DA installation clusters are constructed and energized and the associated communications infrastructure is enabled.

Q. Is Project DA expected to be constructed entirely in Missouri?

A. No. The intended project footprint spans all four neighboring states served by Liberty, namely Missouri, Kansas, Arkansas, and Oklahoma. However, as with the Company's distribution system footprint, the largest portion of the project work is expected to take place in Missouri.

Q. How does the Company plan to recover the portion of the project costs not subsidized by the DOE grant?

A. Once the project costs have been placed in-service the Company will seek regulatory recovery of the prudently incurred project costs that are not covered by the DOE grant contributions from the four retail jurisdictional regulatory bodies. The amounts sought for recovery in each jurisdiction will be allocated based on direct assignment or in accordance with the jurisdictional allocation approach the Company has typically used for rate making purposes.

Q. Is the Company seeking recovery of any Project DA-related investment costs in this case?

A. No. Since none of the Project DA costs have been placed in-service by the end of the Company's proposed update period (September 30, 2024), the Company is not seeking recovery within this specific rate case.

Q. What is the total estimated cost of Project DA, and what portion of it is expected to be covered by the DOE grant?

A. At the time of the submission of the GRIP application in March 2023, Liberty estimated the project's total cost to be approximately $95 million. Based on GRIP program rules, the Company requested the DOE's funding participation in the amount equal to 50% of the project's estimated cost, i.e., $47.5 million. This percentage of project costs is the maximum level of funding participation for a utility of Liberty's size.

Q. What happens if the project's final costs differ from the initial estimate?

A. Under program rules, the DOE's maximum possible contribution is fixed at $47.5 million irrespective of what percentage of total completed project cost this represents. If the Company completes the project for a lower total amount, the DOE's contribution will not exceed 50% of that final lower amount. However, this provision is asymmetrical, meaning that if the project's final total cost ends up being higher than the initial estimate, the DOE's contribution will amount to less than 50% of the cost.

Q. What is the current status of Project DA?

A. The Company received a final sign-off on the award from the DOE on September 21, 2024, nearly a year after being notified that it was selected for an award and commencing the award due diligence activities.

Q. Should the Commission be aware of any specific requirements associated with this project that may be relevant for its future review of the ensuing expenditures?

A. Yes. GRIP-funded projects must meet a variety of eligibility criteria to be deemed eligible for award consideration and ultimately funded. A number of these criteria go substantially beyond the realm of regulatory energy policy that is driven primarily by economics. For example, some of the key requirements under the award include:

- *Compliance with the Davis Bacon Act.* This requires that certain types of project roles be compensated at local prevailing wages as determined by the federal government. The prevailing wage requirement must be adhered to even if it involves paying wages and fringe benefits above the rates specified in the eligible workers' existing employment contracts or collective agreements governing their employment. Additional logistical expenditures are also expected to arise out of the requirement to pay the eligible workers on a weekly basis.
- *Community Benefit Plan Expenditures.* A critical element of award eligibility entails the delivery of a series of commitments established in the Community Benefit Plan portion of applications across four very specific categories, namely:
    - Community and Labor Engagement;

  - Investing in Job Quality and Workforce Continuity;
  - Diversity, Equity, Inclusion and Accessibility; and
  - Justice40 Outcomes, where 40% of all project benefits must flow to 40% of the most disadvantaged communities across the country.

  While many of the commitments can be a function of the anticipated outcomes of the project itself, multiple facets of the plan delivery require steps and expenditures that are not on a critical path of completing an energy infrastructure project under normal operating circumstances.

- *No DOE Cost Recovery Ahead of Award Finalization.* Under GRIP program rules, none of the costs the Company has incurred to date in preparing the grant applications or participating in the ongoing Award Negotiations Process are eligible for recovery from the DOE and cannot be counted towards the cost of the grant. A partial exception applies to costs incurred in ordering long-lead items if they are given a special approval to be incurred before the Award Negotiation process is complete.
- *DOE Awards Are Taxed.* It is the Company's understanding that DOE grants are taxable in the same manner as the revenues from Contributions in Aid of Construction received from customers. The Company is working with its peers through the Edison Electric Institute to fully understand the details of tax treatment and the underlying logistics. However, there appears to be a broad consensus about the tax treatment more generally.

There are two major implications stemming from the above information, some of which the Company learned or was able to formally confirm only after being selected for Award Negotiations. The first is that while the DOE's anticipated contribution will significantly reduce the cost of Project DA to the Company, this contribution is almost certain to be less than 50% of all expenditures. The second and related implication is that the scope of what constitutes a prudently incurred expenditure for a DOE-supported project will invariably differ from that for a normal-course utility project expenditure. This is because the DOE's funding policy objectives extend beyond energy policy and create non-discretionary expenditures that grant recipients would not be expected to incur had they been pursuing the same project outside of the grant framework.

Q. Given the nature of these specific circumstances, does the Company still believe that it is worth pursuing the GRIP grants?

A. Absolutely. Even if the final effective amount of DOE contributions to the GRIP-funded projects ends up being materially lower than 50%, these contributions will still serve to offset a major portion of the costs of reliability improvement, grid hardening, and modernization work the Company was planning to perform in any case. If the Commission and other regulatory stakeholders work with the Company as it navigates this new opportunity for transformative change, we believe that Liberty's distribution system and the communities it serves will reap significant and sustainable benefits from our participation in the GRIP program.

Q. Has the Company submitted any Concept Papers for the second tranche of the GRIP program that commenced in early 2024?

A. Yes. We submitted an updated and improved Concept Paper for the Ozark transmission reinforcement project that was encouraged to proceed to the Full Application stage in the first tranche, but which the Company decided to defer to this year given the volumes of work inherent in putting together a competitive GRIP filing. As I note above, the

Company initially understood that the DOE's direction was that Concept Papers encouraged in the first tranche of the application could proceed directly to the Full Application stage in the program's second cycle, but we were not able to confirm that once the second cycle was underway. Accordingly, the Company elected to re-submit the Concept Paper in the second cycle after ensuring that it addressed the slightly evolved program requirements as articulated in the program's Funding Opportunity Announcement Document.

Q. Did the Company consider updating the scope of the Concept Paper based on its learnings from the first program cycle or any other emerging insights?

A. Yes. While our core proposal remained the same, we added a proposal for a Dynamic Line Rating pilot to be executed in conjunction with the line rebuild and upgrade. The Company believed such a pilot was warranted given the substance of the 2021 FERC Order 881, which directs transmission providers to adopt ambient-adjusted transmission line ratings, and the ongoing investigative work in FERC Docket AD22-5-000, which explores the merits of adoption of full DLR capabilities. Aside from the addition of a modest pilot, the Company's proposal was substantially the same as in the first GRIP cycle.

Q. What feedback did the Company receive on the Concept Paper it submitted in the second tranche of the GRIP application cycle?

A. To our surprise, the DOE did not encourage the Concept Paper to proceed to the full Application stage in this application cycle. While we received some standard explanatory notes substantiating this year's decision, we are not able to identify a clear reason while virtually the same (and arguably enhanced) Concept Paper was declined after being encouraged to proceed a year ago.

Q. Does the Company anticipate submitting any Concept Papers in the GRIP program's third and final cycle in 2025?

A. We have not made that decision yet, and we will likely base it on our further experience from the ongoing Project DA and any feedback we may receive in the course of this application.

Q. Does this conclude your direct testimony?

A. Yes it does.

VERIFICATION

I, Dmitry Balashov, under penalty of perjury, on this 6th day of November, 2024, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Dmitry Balashov