Exhibit No. 20

Liberty – Exhibit 20
Tisha Sanderson
Direct Testimony
File No. ER-2021-0312

Exhibit No.: _____
Issue(s): MPPM and Revenue Requirements – Wind, AMI, and Asbury
Witness: Tisha Sanderson
Type of Exhibit: Direct Testimony
Sponsoring Party: The Empire District Electric Company
Case No.: ER-2021-0312
Date Testimony Prepared: May 28, 2021

Before the Public Service Commission of the State of Missouri

Direct Testimony

of

Tisha Sanderson

on behalf of

The Empire District Electric Company

May 28, 2021

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THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tisha Sanderson. My business address is 602 South Joplin Avenue, Joplin, MO, 64802.

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

A. I am employed by Liberty Utilities Service Corp. ("Liberty") as the Vice President of Finance and Administration for Liberty's Central Region, which includes The Empire District Electric Company ("Empire" or "Company"), as well as, gas, water and wastewater utilities serving in the Central Region. I am responsible for financial reporting, budgeting, and accounting for the Central Region.

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

A. I am testifying on behalf of Empire.

Q. Please describe your educational and professional background.

A. I have a Bachelor of Science degree in business with a concentration in accounting. I am also a Certified Public Accountant licensed to practice in Missouri and have over 23 years of experience in increasingly senior positions within the construction, engineering, and utilities industries. I joined Liberty in August of 2012 and was promoted to Vice President of Finance and Administration for the Central Region in April of 2018.

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

A. While I have not testified before this Commission previously, I have provided testimony before the New Hampshire Public Utilities Commission.

II. PURPOSE AND CONTEXT

Q. What is the purpose of your direct testimony in this proceeding?

A. I explain the basis and calculation of revenue requirements for the critical investments supporting the Company's ongoing pivot towards a more customer centric, economic, and technologically advanced service model, namely:

- the commissioning of 600 Mw of new wind generation (the "Wind Farms");
- the retirement of the Asbury Coal Plant ("Asbury"); and
- the deployment of Advanced Metering Infrastructure ("AMI").

When combined, these investments result in sustainable long-term savings for our customers over the next two decades. In the immediate timeframe, they also act to significantly reduce the amount of the increase being sought in this application. For example, the net effect of the Company's proposal regarding the Asbury plant and the requested revenue requirement of the new Wind Projects results in a net revenue requirement savings of $14.5 million. For their part, the AMI deployment is projected to yield $195M in savings over these assets' lifecycle.

My testimony also covers the Market Price Protection Mechanism ("MPPM") approved by the Commission in Case No. EA-2019-0010 where the Company secured the Certificates of Convenience and Necessity for the three wind projects (the "CCN case"). The MPPM represents an added safeguard that the Commission ordered, and the Company implemented to mitigate potential customer risks stemming from the deployment of wind

projects. While it is in the early days for the wind projects, the MPPM further supports the wind projects performance in the expected range of customer benefits.

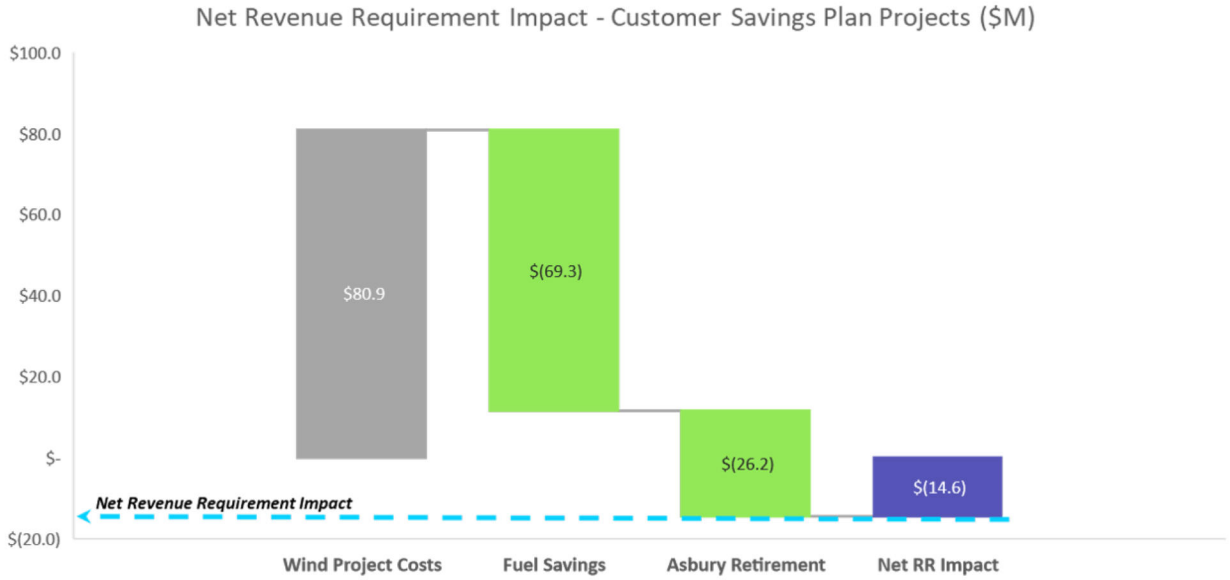

Figure 1: Net Revenue Requirement including fuel savings, Asbury and Wind

Q. Why have a separate piece of testimony focused on the Revenue Requirement calculation of just a handful of initiatives?

A. There are three main reasons why the Company believes that added focus is warranted for these components of the overall revenue requirement, as they reflect:

- customer savings in revenue requirement and other related mechanisms;
- specific Commission guidance from past proceedings; and
- net new types of assets entering the Company's rate base.

On balance, the investments in question are a product of customer focused managerial decisions that respond to changing energy sector economics, responsibly leveraging new technology, and optimizing both public policy tools and commercial arrangements to deliver tangible value for customers and shareholders alike.

III. WIND PROJECTS

Q. Please briefly summarize the background of the wind projects in question.

A. During the first half of 2021, Empire acquired interest in three wind generation projects through a holding company. The transactions were grounded in previously secured Commission approvals in cases EO-2018-0092 (the "Customer Savings Plan case") and EA-2019-0010 (the "CCN case"). My colleagues Todd Mooney, Shaen T. Rooney and Tim Wilson provide the details concerning the construction, acquisition, financing, operation, and market revenue generation for these projects in their respective direct testimony.

Q. Has the Company included the costs of the Wind Projects in its cost of service in this case? If so, please explain how.

A. Yes. The Company reflected its Wind Project investments as plant in service and seeks to recover the associated Cost of Capital and the Operation and Maintenance ("O&M") Expenses associated with the projects. Importantly, the Wind revenue requirement is reduced approximately 67% by the wind net operating income and associated amortization

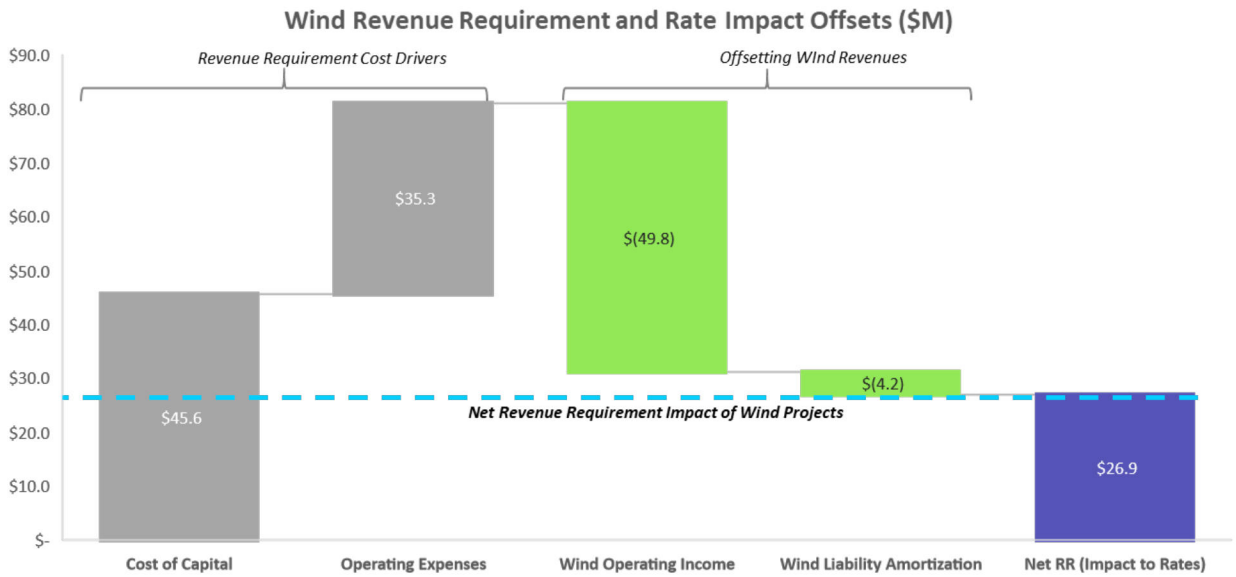

Figure 2: Wind Revenue Requirement Calculation

of the wind revenue liability . Figure 2 illustrates this concept using a waterfall diagram, while I address each component in detail below.

It is also important to note that there are several other cost and/or revenue drivers associated with the wind projects, which the Company will seek to recover (or credit to) customers directly through the Fuel Adjustment Clause ("FAC"). I discuss these additional items below as well. As noted above, before completing my wind-related testimony, I also address the MPPM mechanism that provides another layer of potential downside protection for our customers, should the expected wind revenues not materialize to the expected degree.

Q. What cost drivers make up the Rate Base of the Wind Projects?

A. The rate base amount upon which the Cost of Debt and Return on Equity are calculated reflects the net book value of:

- the physical plant supporting wind generation; and
- other capitalized costs that the company is required to account for.

I discuss each component below.

The Physical Plant

The physical plant is made up of wind turbine assets and other civil and electrical infrastructure required to safely generate, collect and transmit the electricity towards the load centers where it is consumed. Please refer to the Direct Testimony of the Company Witness Shaen T. Rooney for a more detailed description of these assets.

Other Capitalized Costs

Also included in the Wind Project Rate Base are the appropriate amounts to account for the costs of future removal of the wind assets known as the Asset Retirement Costs

("ARC") and Asset Retirement Obligations ("ARO"), and allocations for Accumulated Deferred Income Tax ("ADIT").

Q. What are the Asset Retirement Costs and Obligations and why are they in the Rate Base now?

A. The ARC is a rate base entry that captures the capitalized cost of Empire's legal obligation, ARO, to eventually dismantle the Wind Projects. All of Empire's Wind Projects are located on leased land easements, each of which has a definitive term of 30 years. The lease agreements establishing the easements obligate the Company to remove all the infrastructure and restore the land to near its original state once the agreements expire.

The definitive expiry date of the lease agreements is the reason why the ARO obligation arises. Under Accounting Standards Codification ("ASC") 410-20-25 an ARO exists when the obligation to perform the asset retirement activity is *unconditional* even though there may be uncertainty about how and when the obligation will ultimately be settled. Accordingly, organizations must capitalize asset retirement costs by increasing the carrying amount of the related long-lived asset by the same amount of the liability for an ARO. In other words, the expected net present value of asset retirement costs and restoration are added to the value of the actual plant, and are depreciated over time. An equal amount is established as a liability representing the obligation to remove the assets on which interest is accreted in order to arrive at the future value needed to dismantle the Wind farms It is also important to note that recording the ARC as plant is consistent with the Commission's Orders in the Customer Savings Plan case[1] and the CCN case.[2]

[1] *See also,* File No. EO-2018-0092, *In the Matter of the Application of The Empire District Electric Company for Approval of Its Customer Savings Plan*, Report and Order (issued July 11, 2018), Ordered Paragraph 2

[2] File No. *EA-2019-0010, In the Matter of the Application of The Empire District Electric Company for a Certificates of Convenience and Necessity Related to Wind Generation Facilities*, Report and Order (issued June 19, 2019, effective June 29, 2019), Ordered Paragraph 6(h)(i).

Q. What happens if the Company and the landowners choose to extend the terms of the easement lease agreements in the future?

A. The Company would make the appropriate adjustments to reflect the net impact of the extension relative to the amounts collected to date, the expected remaining service life of the assets, and any other applicable changes.

Q. How is the Accumulated Deferred Income Taxes (ADIT) component of the Rate Base calculated?

A. For Empire's ownership share it is calculated in the same manner as it is for all other regulated plant. Please see the testimony of Company witness Charlotte T. Emery for the discussion of income taxes and deferrals.

Q. What makes up the Operating Costs component of the Wind Revenue Requirement?

A. The majority of these recurring expenses related to the costs that the Company and its service providers incur in servicing the wind projects themselves – including the day to day site, system and market operations, asset management analytics and physical asset and site upkeep work, insurance expenditures, lease payments to the easement landowners, ongoing environmental mitigation and others. The scope and nature of these services and the associated payment terms and conditions are prescribed in a series of agreements that my colleague Shaen T. Rooney discusses in his testimony.

Rounding out the Operating Expenses are the annual Depreciation expense and the Property Taxes assessed by the taxing authorities.

Q. Do the local property taxes include those for the wind farm located in Kansas?

A. No. There are no property taxes assessed to the Neosho Ridge Wind Project for the ten years immediately following the taxable year in which construction or installation of the

Kansas Wind farm is completed. This is a result of Kansas Statute Annotated §79-201, which exempts an applicant from paying property tax. However, the Company entered an agreement to pay in lieu of property tax $1,000,000 per year to Neosho County.

Q. How did the Company calculate the Depreciation rate for the calculation of the net Rate Base Wind Projects?

A. We propose to use the depreciation rate of 3.33% for all the wind assets based on the Commission's Order in the CCN Case. As Dane Watson explains in his Direct Testimony, there is not enough information about the Wind Projects at this time to have included them in his depreciation study, hence the adoption of the Commission provided depreciation rate. The proposed rate assumes the recovery of the Wind Projects over a thirty-year period of the projects' easement leases. At this point the depreciation rate does not incorporate the dismantlement costs, asset removal or salvage value, all of which can be explored at the time when a future wind asset depreciation study is completed.

Q. Please describe the market revenues from wind power sales that are included in the Wind Project Revenue Requirement and serve to offset their total rate impact.

A. There are two components to the market revenues reflected in the revenue requirement relating to the Wind Projects. The first component reflects the expected annual revenues the Wind Projects will produce once they are included in base rates. As captured in Figure 2 at the start of this section, the Company estimates this value to be $49.8 million. The second component reflects the estimated revenues that the Wind Projects will generate net of expenses between the time of being acquired and when new rates go into effect following the conclusion of this rate case. Consistent with the Figure 2 above, the annual amount of this item is estimated to be $4.2 million.

Q. What is the background to the Company's decision to use the Wind Project revenues collected prior to the conclusion of this rate case to offset the revenue requirement?

A. In Empire's last general rate case (Case No. ER-2019-0374), the Commission's Report and Order stated the Company could not flow through any costs or revenues relating to the Wind Projects prior to the Commission approval of the revenue requirement relating to the Wind Projects being placed in base rates. Since the PISA approach that Empire elected allows it to defer and recover 85% of the depreciation and return on its Wind Project investments, the Company is proposing to offset the wind revenue requirement with 85% of Empire's Missouri jurisdictional share of the net revenues collected from the time the projects' were acquired through the date rates go into effect and the Company is able to recover the PISA deferral. The percentage of revenues proposed to be allocated in this manner aligns with the value of PISA deferrals related to the wind assets.

Q. Please describe the Wind Project-related costs and revenue items which you previously mentioned will be flown through the FAC rather than included in base rates.

A. Empire proposes that the cost impact of items such as Production Tax Credits ("PTCs"), Renewable Energy Credits ("RECs"), Hedge Net Settlements, PAYGO[3] contributions and other variable costs such as cash distributions related to tax equity be netted against the Wind Projects' market revenues, with the balance flowed through to customers as part of Empire's FAC charge, re-set by the Commission every six months. The Direct Testimony

[3] Contingent Contributions (referred to as "Paygo") represent additional contributions of cash by the tax equity partners to Empire Wind Holdings, LLC based on actual production in excess of a threshold. Paygo contributions received by Empire Wind Holdings, LLC are distributed to Empire and hence reduce the cost of service to customers.

of Company witnesses Todd Mooney and Aaron J. Doll describes the nature of these items in more detail.

Q. What is the net annual revenue requirement for the Wind Projects between the base rate and FAC impacts?

A. The net annual revenue requirement for the Wind Projects included in the Company's cost of service is projected to be $26.9 million. This net revenue requirement amount is approximately 67% lower than the sum of Wind Projects' annual Cost of Capital and Operating Costs due to the offsetting effect of electricity sales revenues using zero-dollar fuel that the Company is using to offset the rate impact for its consumers. This tangible and sustainable value would not have been possible without the Company's decision to retire Asbury when it did and replenish its installed capacity with clean and sustainable wind generation financed in conjunction with tax equity partners.

While it effectively traces the same calculation as the Figure 2 at the start of this section, Figure 3 below provides a more detailed accounting breakdown of the net Wind Project revenue requirement calculation.

Figure 3

Line No.	Description	Reference	Total Missouri Wind Project
	(a)	(b)	(d)
	Rate Base		
1	Rate Base	Schedule B-2	$ 525,311,182
2	Rate of Return Requested	Schedule E-1	7.03%
3	Return on Rate Base	Line 1 x Line 2	$ 36,951,954
	Operating Expenses		
4	Non-FAC Operating Expenses	Schedule F-1	35,286,601
5	Income Taxes		-
6	Operating Income (Loss) After Taxes	Line 4 - Line 5	35,286,601
	Cost of Capital		
7	Rate Base	Line 1	525,311,182
8	Weighted Cost of Debt	Schedule E-1	1.79%
9	Interest Deduction	Line 7 x Line 8	9,405,285
10	Weighted Cost of Equity	Schedule E-1	5.24%
11	Equity Return	Line 7 x Line 10	27,546,670
12	GRCF	2021 Rev. Req. Model	1.3130
13	Total Equity Return	Line 11 x Line 12	36,169,519
	Project Revenue Requirement		
14	Operating Expense	Schedule F-1	35,286,601
15	Total Equity Return	Line 13	36,169,519
16	Total Debt Return	Line 9	9,405,285
17	**Project Revenue Requirement**	Sum: Lines 14 - 16	**$ 80,861,405**
	Reductions to Rates		
18	EDE FAC Operating Income	Schedule F-1	$ 49,760,834
19	Wind Liability Amortization	Schedule F-8	$ 4,203,532
20	**Net Impact to Rates**		**$ 26,897,038**

Q. Please describe the Wind Projects adjustments you are sponsoring.

A. The specific adjustments are as follows, and their nature is described above:

- RB ADJ 1 for plant additions specific to the wind projects and the respective Accumulated Depreciation.
- RB ADJ 10 for the wind projects asset retirement obligations

- RB ADJ 11 includes the projected ADIT balance for the wind projects at the end of the update period in this case.
- REV ADJ 14 and EXP ADJ 25 include the O&M costs and revenues for four affiliate contracts: Asset Management and Administrative Services Agreement ("AMA"); Energy Management Services Agreement ("EMSA"); and Operations and Maintenance Agreement ("OMA") each between Empire and each of the Wind Project companies; and the Affiliate Services Agreement ("ASA") which is between Empire and Algonquin Power Fund (America) Inc.
- EXP ADJ 25 also includes lease expense, property tax, service and maintenance agreement costs, insurance, and post-construction environmental costs for the Wind Projects. Please see the testimony of Witnesses Shaen T. Rooney and Aaron J. Doll for an explanation of the affiliate contracts.

IV. MARKET PRICE PROTECTION MECHANISM ("MPPM")

Q. Please describe the MPPM mechanism that you stated is designed to further reduce the risk potentially faced by customers due to the Wind Projects?

A. In Case No. EA-2019-0010, the Company, working with stakeholders, developed, and received approval from the Commission of, the MPPM that will compare the Wind Project cost (revenue requirement) to Wind Project benefits (Wind Project market revenues, plus the avoided capacity costs for two expiring purchase power agreements ("PPAs")) from the Elk River and Meridian Way wind facilities.

The MPPM is another layer of protection for the Company's customers, as it provides for sharing of risk between Missouri jurisdiction customers and shareholders associated with the possibility that actual market prices and/or actual energy production

from the Wind Projects turn out to be less than what has been projected. The MPPM shields customers from revenue shortfall risk of up to $52.5 million over the first ten years after the Wind Projects are included in customer rates ("Guarantee Period") should the actual prices and energy production be less than anticipated by Empire.

Q. Please summarize how the MPPM works.

A. The MPPM goes into effect on the first day of the month after the last Wind Project is placed into rates and remains in effect for 10 years following the effective date of rates resulting from the first general rate case in which all Wind Projects are included in rates. The Mechanism operates by comparing the amount of revenue generated from sales of energy from each Wind Project into the SPP Integrated Marketplace to the Wind Revenue Requirement ("WRR") associated with the Wind Projects, and to the value of replacing the energy from the Elk River and Meridian Way PPAs once they have expired (the "PPA Replacement Value").

Q. Is there a mathematical formula for calculating the MPPM benefit?

A. Yes. The formula for calculating the Annual Wind Value ("AWV") benefit to customers consists of several steps illustrated below:

Step 1: Calculate Total Annual Wind Value

$$AWV_{Total} = \text{SPP IM sales revenues} + \text{PPA Replacement Value} - WRR$$

Step 2: Identify Customer Portion of the Annual Wind Value known as the Annual Sharing Value (ASV)

$$ASV_{Year\ n} = AWV_{Total} \times 50\%$$

Step 3: Add the latest year's ASV to the previous years' ASVs up to Year 10, to determine running total of risk sharing benefits (if any):

$$If \sum ASV_{Year\ n,\ ASV\ Year\ n+/-1\ldots\ (first\ 10\ Years)} < 0 \rightarrow Record\ Liability$$

$$If \sum ASV_{Year\ n,\ ASV\ Year\ n+/-1\ldots\ (first\ 10\ Years)} \geq 0 \rightarrow No\ Action$$

If the ASV Sum at the end of Step 3 is negative, a regulatory liability, it shall be amortized and returned back to customers starting with the effective date of rates in the first rate case after the end of the 10-year Guarantee Period.[4] Conversely, if the Wind Projects perform as projected or exceed projections, customers will retain 100% of the benefits provided by the Wind Projects. These factors will be updated by the Company on an annual basis using the actual values during the MPPM Guarantee Period.

As the above explanation illustrates, the MPPM represents an asymmetric risk sharing mechanism that benefits the Company's customers in the first decade of the Wind Projects' operations, since they stand to gain 100% of the Wind Projects' revenue upside and only 50% of the downside.

Q. How will the MPPM be recorded on the Company's books?

A. The Company will produce a calculation annually based on the MPPM formula and record any regulatory asset/liability that results from the calculation. In addition to tracking the ASV annually, the Company will make the information, and supporting documentation, available to the parties.

[4] File No. *EA-2019-0010, In the Matter of the Application of The Empire District Electric Company for a Certificates of Convenience and Necessity Related to Wind Generation Facilities*, Report and Order (issued June 19, 2019, effective June 29, 2019), Exhibit B).

V. ASBURY RETIREMENT

Q. Please briefly describe Asbury and its retirement circumstances.

A. Asbury was a coal-power plant constructed in 1970. As recently as 2014, the plant underwent significant emission control upgrades, to comply with environmental policy requirements, which the Commission approved.[5] As it continued operating, its operating economics continued to erode as detailed in Aaron J. Doll's Direct Testimony.

The Company analyzed retiring Asbury as part of its Generation Fleet Savings Analysis presented to the Commission in 2017 as well as in its 2019 Integrated Resource Plan ("IRP"). Most recently in the 2019 IRP, Empire determined that retirement of Asbury in 2019 would yield the benefits of $93 million over 20 years for its customers when compared to its continued operation until its end of useful life.[6] Pursuant to this analysis, Asbury was retired on March 1, 2020.

Q. Was the Company directed to track the costs related to the impact of retiring Asbury?

A. Yes. In Case No. ER-2019-0374, the Commission issued an Amended Report and Order on July 23, 2020 requiring the Company to establish an Accounting Authority Order ("AAO") with regard to the retirement of Asbury. The AAO directed the Company to establish regulatory asset or liability accounts, beginning January 1, 2020, to reflect the impact of the closure of Asbury and required the Company to separately track and quantify the changes from the base amounts, reflected in Appendix D of the Global Stipulation and Agreement submitted in that case, for the following categories of rate base and expense reflected in the Commission's Order:

[5] File No. ER-2014-0351, *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area*.
[6] File No. EO-2019-0049, 2019 IRP, Volume 7, pg. 10.

a. Rate of return on Asbury Plant,

b. Accumulated Depreciation,

c. Accumulated and Excess Deferred Income Tax,

d. Fuel inventories assigned to the Asbury Plant,

e. Depreciation expense,

f. All Non-fuel/ non-labor operating and maintenance expenses,

g. All labor charges for maintaining and operating the Asbury Plant,

h. Property taxes assigned to the Asbury Plant, and

i. Any costs associated with the retirement of the Asbury Plant, including dismantlement and decommissioning - Non-Empire labor excluded.

Q. Were there any other additional items the Commission ordered the Company to track in the AAO?

A. In addition to the items stated above, the Commission also ordered the Company to include the following items which were proposed by OPC's witness:

a. Cash working capital and income tax gross up associated with Asbury,

b. Any fuel or SPP revenues or expenses associated with Asbury that do not flow through the FAC, and

c. Revenue from scrap value or value of items sold.

Q. Did the Company comply with the Commission's AAO directions?

A. Yes. The Commission's original Report and Order was issued on July 1, 2020, and effective on July 11, 2020.[7] The Company established the regulatory accounts to track

[7] ER-2019-0374, Report and Order, p. 105-106.

the costs as of January 1, 2020, after the Report and Order was issued directing the Company to do so.[8]

Q. What is the estimated balance of the Asbury AAO?

A. The estimated balance of the items to be tracked through the AAO as of June 30, 2021, the update period in this case, is a regulatory liability of $44.5 million as shown below in Figure 4. The Company will update the AAO account balances during the pendency of this case with actuals.

Figure 4

ASBURY AAO		
1	Plant In Service	$ (217,663,073)
2	Remaining Plant	(2,277,616)
3	Accumulated Depreciation	62,618,776
4	Remaining Plant Accumulated Depreciation	(90,624)
5	Fuel Inventories	(2,414,632)
6	Cash Working Capital	(128,983)
7	ADIT	(63,372)
8	Excess ADIT	878,783
9	**Net Rate Base/Regulatory Asset**	**(159,140,741)**
10	Return On Asbury	(14,486,088)
11	Revenue From Scrap Value or Value of Items Sold	(10,248)
12	Any Fuel or SPP Revenues/Expenses not flowed through FAC	-
13	Depreciation Expense	(13,914,240)
14	All Non-Fuel/Non-Labor Operating & Maintenance Expenses	(5,931,161)
15	Labor Expenses	-
16	Property Taxes	(2,860,004)
17	Non-Labor Asbury Retirement/Decommissioning Costs	3,290,545
18	Asbury AAO Liability Before Gross Up:	(33,911,196)
19	Gross Revenue Conversion Factor	1.3130
20	**Regulatory Liability**	**$ (44,526,314)**

[8] Subsequently, the Commission issued an Amended Report and Order on July 23, 2020, with an effective date of August 2, 2020. ER-2019-0374, Amended Report and Order, p. 118-119.

Q. How did the Company reflect Asbury's retirement in its Revenue Requirement?

A. The Company reflected adjusted regulatory asset and liability balances at June 2021 as components of rate base, and included the associated amortization of them in its proposed revenue requirement. In addition, the Company included a regulatory asset and associated amortization related to the Company's FAC filing, ER-2020-0311. Finally, the Company removed the revenue previously reserved from the regulatory liability for which the Company seeks recovery. The adjustment amounts included in the revenue requirement are shown in Figure 5 below.

Figure 5

Description	SCH/WP	Adjustment Amount
BALANCE SHEET		
Remove Asbury ARO-unsettled & the Non-Missouri Portion of Abandoned Projects	RB ADJ 9	(8,501,833)
To include Asbury Settled ARO costs	RB ADJ 9	1,426,482
Asbury AAO Liability	RB ADJ 10	(10,359,345)
Reclass Asbury portion of Excess ADIT into separate liability	RB ADJ 10	(16,055,610)
Reclass Asbury portion of Excess ADIT out of Total Excess ADIT account	RB ADJ 10	16,055,610
Reclass Asbury portion of ADIT into regulatory liability	RB ADJ 10	(32,338,406)
Reclass Asbury portion of ADIT out of ADIT account	RB ADJ 14	32,338,406
INCOME STATEMENT		
To reverse the amount of test year revenues being offset for the Asbury AAO liability.	REV ADJ 6	13,890,879
Asbury AAO Regulatory Asset Amortization (26 yr. amortization)	EXP ADJ 9	4,319,921
Asbury Coal Amortization Adjustment re: Asbury Coal Adj ER-2020-0311 (26 yr. amortization)	EXP ADJ 9	58,955
Asbury AAO Regulatory Liability Amortization - less Asbury return and Jan/Feb expenses incurred prior to retirement (2 yr. amortization)	EXP ADJ 9	(12,125,112)

Q. Please describe RB ADJ 9 - Asbury adjustments.

A. RB ADJ 9 removed the asset retirement costs and associated asset retirement obligations that have not been settled from the test year Asbury regulatory asset balance. The total impact of this adjustment was to 1) reduce the value of Asbury for the purpose of calculating the regulatory asset by $8,501,833, resulting in a pro forma balance of $159,414,474, which represents Missouri's portion of Asbury unrecovered plant assets,

accumulated depreciation, and Asbury abandoned project costs and 2) include in the cost of service various environmental expenditures, such as costs incurred for the removal of asbestos and the handling and retirement of the coal ash ponds at the Asbury plant that have been identified as part of the legal obligations associated with the retirement of Asbury and which have yet to be recovered in rates.

Per the Amended Report and Order in Case No. ER-2019-0374, Commission Staff verified the capital expenditures incurred by the Company through the true-up period in that case (January 2020) were both prudent and necessary.[9] Therefore, this adjustment is to include in the cost of service the costs previously deemed prudent by the Commission Staff, the additional capital expenditures that have been incurred by the Company through the end of the test year of this current case (September 2020), and any settlements that are expected to be paid out through the end of the update period (June 2021).

The Amended Report and Order in ER-2019-0374 directed the Company to offset the incurred costs against the remaining Asbury accumulated depreciation reserve[10]; however, due to Asbury being retired at the test year end, there was no reserve to offset against. Therefore, the Company is proposing $1,684,949 (Total Company) or $1,426,482 (Missouri jurisdiction) be included in the cost of service as a regulatory asset.

Q. Are there any other Asbury regulatory assets included in the revenue requirement?

A. Yes. Per the Global Stipulation and Agreement, as well as, the Order in Case No. ER-2020-0311, the Company deferred its Asbury coal inventory adjustment to FERC Account 182.3, Other Regulatory Asset, for future ratemaking consideration in the Company's next general rate case. There was no additional amount added to this regulatory asset; therefore, the pro

[9] ER-2019-0374 Amended Report and Order, Page 149.
[10] ER-2019-0374 Amended Report and Order, Pages 149-150

forma Missouri ending balance for the Asbury Coal Regulatory Asset being included in the Company's revenue requirement is $1,532,832.

Q. Please describe RB ADJ 10 Asbury adjustment.

A. RB ADJ 10 updates the test year Missouri AAO regulatory liability balance $13,890,879 for costs expected to be incurred through the June 2021 update period of this cause. In addition, this adjustment removes the January and February 2020 expenses the Company incurred for Asbury prior to its retirement date. This adjustment also removes the test year balance of return reserved for Asbury from the AAO liability. This results in a Missouri jurisdictional adjustment of $10,359,345, making the pro forma balance of the Asbury AAO regulatory liability $24,250,224.

Q. Please describe RB ADJ 10 Asbury Excess ADIT reclass.

A. This adjustment is to reclass $16,055,610 of excess ADIT related to Asbury's portion of retired plant from its original general ledger account into a separate regulatory liability account. This adjustment has a net effect on rate base of zero.

Q. Please describe RB ADJ 10 and RB ADJ 14 Asbury ADIT reclass.

A. This adjustment is to reclass $32,338,406 of ADIT related to Asbury's portion of retired plant from the deferred taxes general ledger account into a regulatory liability account. This adjustment has a net effect on rate base of zero.

Q. Please describe REV ADJ 6 Asbury adjustments.

A. The Company reduced revenues and established a regulatory liability to reserve the impacts of retiring Asbury as ordered by the Commission. This adjustment reverses the reduction to test year revenues for costs that the Company seeks recovery for in this cause, resulting in a Missouri level adjustment to increase revenues by $13,890,879.

Q. Please describe Expense ADJ 9 Asbury adjustments.

A. Expense ADJ 9 includes amortization expense for: 1) the AAO regulatory asset as adjusted 2) the Asbury coal regulatory asset and 3) the AAO regulatory liability.

Q. What amortization period is proposed for the AAO regulatory assets?

A. The proposed amortization period is 26 years, which is consistent with the 2019 IRP analysis of the benefits of retiring Asbury versus continued operation. Using this timeframe decreases the rate impact customers currently incur related to Asbury. The depreciation rates currently included in rates for the recovery of Asbury were based on a retirement date of 2035, which would have recovered Asbury over 13 years from the estimated date rates would go into effect in this cause, versus the Company's proposed 26-year recovery period. This extension results in an annual amortization adjustment of $4,319,921 (Missouri jurisdiction) which reduces the customer burden relative to the original assumption.

Q. What amortization period was used for the coal regulatory asset?

A. The Company proposes to amortize the coal regulatory asset over the same time period as the AAO regulatory asset, which results in an additional adjustment of $58,955 (Missouri jurisdiction) being included in the cost of service.

Q. What amortization period was used for the AAO regulatory liability?

A. The Company proposes accelerating the return of these funds for the benefit of our customers by amortizing the AAO regulatory liability over two years adjusted for two items: 1) the expenses for January and February depreciation expense, property tax, and non-fuel/non-labor operation and maintenance expenses that were incurred prior to Asbury's retirement date and 2) the return on the Asbury AAO net rate base. In amortizing

the $24.3M Missouri AAO regulatory liability described above over two years, this results in an annual decrease to amortization expense of $12,125,112.

Q. What amortization period is proposed for Asbury's portion of ADIT and Excess ADIT included in the AAO?

A. The Company included an amortization period of 26 for both ADIT and the protected and unprotected portion of Excess ADIT ("EADIT"). Per IRS rules, and FERC regulations[11], the Company cannot return excess tax reserve any quicker than if the property had remained public utility property. In addition, in order to use a normalization method of accounting, §168(i)(9)(A)(i) requires a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account (regulated tax expense), to use a method of depreciation for property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for establishing its cost of service for ratemaking purposes. [12]

Q. Is the Company continuing to incur costs related to Asbury?

A. Yes. The Company continues to incur expenses for taxes, insurance, and other costs to keep the property safe until it is dismantled. As indicated in the Direct Testimony of Empire witness Drew W. Landoll, Empire was able to re-purpose a portion of Asbury so it could be used in the operation of the Company's Wind Projects and new solar generation.

Q. Will the Company incur costs in the future related to the portion of Asbury that has been retired?

[11] 26 CFR 601.105: Examination of returns and claims for refund, credit, or abatement; determination of correct tax liability. (Also: § 1.168(i)-3)
[12] IRS Notice 2019-33

A. Yes. The Company will incur costs for decommissioning and/or disposal of retired assets and will also incur costs related to environmental monitoring of the coal ash pond. Please see the Direct Testimony of Empire witness Drew W. Landoll for further discussion on the Asbury plant decommissioning and environmental monitoring.

Q. How is the Company proposing to recover the continuing and future costs associated with Asbury?

A. The Company proposes to continue to track the continuing and future costs, including decommissioning, through the Asbury AAO until the facility has been fully decommissioned. By tracking these costs, it ensures customers pay no more or no less than the actual expenses incurred. In the first rate case following the decommissioning of Asbury, Empire will propose an amortization of these future costs.

Q. Are there other costs the Company proposes to track through the Asbury AAO?

A. Yes. The Company proposes to track the return to customers of the excess ADIT and other regulatory liability costs through the Asbury AAO so that any potential excess refunds of these costs to customers may offset the continuing and future costs related to Asbury as described above.

Q. What is the annual revenue requirement impact of the Company's Asbury proposal?

A. The annual revenue requirement for the impact of Asbury included in the calculation of base rates in this cause is $529,473. Figure 6 compares the Company's proposal with the calculation of the Asbury's revenue requirement that is currently being collected in base rates. As can be inferred from netting out the current and proposed Revenue Requirement calculations (columns (c) and (d) respectively), the Company's proposal results in annual revenue requirement savings of $26.2M as compared to the costs included in ER-2019-

0374. When compared to the annual value of wind-related revenue requirement offsets, which Asbury's retirement enabled, the proposed Revenue Requirement figure underlying the plant's treatment that the Company seeks is very modest.

Figure 6

Line No.	Description	Reference	Total Missouri Asbury (Retired Plant) Base Rates ER-2019-0374	Total Missouri Asbury (Retired Plant) Proposed ER-2021-0312
	(a)	(b)	(c)	(d)
1	Net Retired Asbury Plant		$ 156,824,597	$ 159,414,474
2	Asbury Environmental Regulatory Assets		-	1,426,482
3	Fuel Inventories		3,947,465	1,532,832
4	Cash Working Capital		(128,983)	(128,983)
5	ADIT		(32,275,034)	(32,338,406)
6	Excess ADIT		(16,934,393)	(16,055,610)
7	Asbury AAO Liability		-	(24,250,224)
8	Net Rate Base	(Line 1 thru Line 7)	111,433,651	89,600,566
9	Revenues Related to Retired Plant		-	-
10	Expenses/Amortization Related to Retired Plant		16,864,061	(7,746,235)
11	Operating Income (Loss) Before Taxes	(Line 9 - Line 10)	(16,864,061)	7,746,235
12	Effective Tax Rate		23.84%	23.84%
13	Income Taxes	(Line 11 x Line 12)	(4,020,409)	1,846,710
14	Operating Income (Loss) After Taxes	(Line 11 - Line 13)	(12,843,652)	5,899,525
15	Current Rate of Return	(Line 14 / Line 8)	-11.53%	6.58%
16	Rate of Return		6.77%	7.03%
17	Required Net Operating Income	(Line 8 x Line 16)	7,539,601	6,302,771
18	Income Deficiency	(Line 17 - Line 14)	20,383,253	403,246
19	Gross Revenue Conversion Factor		1.3130	1.3130
20	**Asbury Revenue Requirement:**	(Line 18 x Line 19)	**$ 26,763,760**	**$ 529,473**

VI. AMI

Q. Please describe the AMI investment.

A. As described in the Direct Testimony of Company witness Chad Hook, AMI is a comprehensive metering solution working in concert to create two-way communications between customer meters and the utility. AMI meters, sometimes referred to as "smart meters," are digital meters with advanced features and capabilities beyond traditional electricity meters. The meters transmit information to field collectors, forming a mesh network, which is flexible in that the meters route data via nearby devices creating a mesh

network of coverage. Within the network, each meter serves as a repeater to help transfer the data to the collectors, which then transmit the information to the AMI control center through a cellular network. Please see Mr. Hook's Direct Testimony for a more detailed description of this project including the progress of implementation; customer benefits of AMI; and operational efficiencies enabled by AMI.

Q. Are the customers expected to experience savings associated with the AMI project?

A. Yes. The new meters have two-way electronic communication. Meter reads as well as remote connects and disconnects may be achieved electronically, thereby eliminating expenses to manually read meters such as labor and labor related costs, vehicle expense, and related overheads. The Company estimates that over a 20-year forecast period, these savings will amount $195M, or on a present value basis $107M.

Q. Did the Company make an adjustment to its revenue requirement to reflect any operational benefits or efficiencies it anticipates to realize as a result of its AMI implementation?

A. Yes. Based on anticipated operational savings, the Company included a pro forma adjustment to reflect a reduction in meter reading expenses. See EXP ADJ 29 below.

Q. How is the AMI investment reflected in the Company's cost of service?

A. The Company reflected the AMI investment in plant and included the operation and maintenance ("O&M") expense, depreciation, and taxes relating to AMI in its cost of service. Figure 7 below shows the adjustment amounts included in the revenue requirement for the AMI project.

Figure 7

Description	SCH/WP	Adjustment Amount
BALANCE SHEET		
To include AMI Plant in Service	RB ADJ 1	23,654,446
To include AMI Accumulated Depreciation	RB ADJ 1	(1,020,580)
To reflect the regulatory asset for stranded meters	RB ADJ 9	9,010,642
To remove stranded meter costs from Plant in Service and Accumulated Depreciation	RB ADJ 15	(9,010,642)
INCOME STATEMENT		
To reflect an annual amount of revenues received from customers who have opted out of using the AMI meters.	REV ADJ 7	286,200
To reflect an annual amount of amortization related to the stranded meters regulatory asset	EXP ADJ 9	500,591
To include costs to educate customers about the proposed TOU program.	EXP ADJ 14	139,827
To include outside service epenses needed for the AMI project based on pricing sheets from third-party vendors.	EXP ADJ 26	1,205,127
To reflect the savings related to the reduction of meter readers needed after deployment of the AMI meters.	EXP ADJ 29	(1,005,247)

Q. Please describe RB ADJ 1 for the AMI Project.

A. RB ADJ 1 adjusts plant in service to reflects plant additions made after the test year but expected to be in service by June 30, 2021, the Update period. Included in that adjustment is $23.65 million of plant related to the AMI Project. It also includes an adjustment to increase accumulated depreciation by $1.02 million for a total net adjustment of $22.63 million.

Q. Please describe RB ADJ 9 for the AMI Project.

A. RB ADJ 9 reflects the estimated balance for the stranded meters replaced by the new meters as a part of the AMI project. The Company is requesting a regulatory asset of $9,010,642 to be included in rate base.

Q. Have other jurisdictions addressed recovery of retired meter costs due to AMI deployment?

A. Yes. In Missouri, Kansas City Power and Light ("KCP&L") received recovery by adjusting its meter reserve account for the stranded costs.[13] Oklahoma Gas and Electric ("OG&E") in Oklahoma started its Smart Grid project in 2010 and received approval to recover its retired meter costs driven by its AMI program over a six-year period.[14]

Q. Please describe RB ADJ 15 for the AMI Project.

A. RB ADJ 15 removes the stranded meter costs from plant in service and accumulated depreciation as of the update period. The net amount is the amount requested to be included in rate base as a regulatory asset, which results in a decrease to rate base by $9,010,642.

Q. Please describe REV ADJ 7 for the AMI Project.

A. REV ADJ 7 reflects the estimated revenue related to the monthly opt-out fees which the Company expects to receive for those customers who choose not to have electronically read meters. This adjustment increases revenues by $286,200 on a Missouri jurisdictional level.

Q. Please describe EXP ADJ 9 for annual amortization related to the stranded meters regulatory asset.

A. The Company is proposing an 18-year amortization period related to the regulatory asset for stranded meters described above, which results in an annual amortization of $500,591.

Q. Is the Company proposing an educational campaign related to TOU rates?

A. Yes. As stated in a Missouri Smart Grid Report,[15] "before implementing time of use rates, it is critical that customers be provided sufficient education to understand the new tariff and how their behavior and decisions will impact their bill." Therefore, the Company is

[13] ER-2014-0370 Order Approving Stipulation and Agreement Issued July 17, 2015
[14] OG&E Cause No. PUD 201000029 Order No. 576595 pg.18.
[15] Missouri Smart Grid Report 2014

developing plans to educate customers about TOU Rates through a variety of communication mediums and budgeted costs as shown below in Figure 8 and Figure 9.

Figure 8

General Customer TOU Education

Target Audience: Liberty's Missouri Electric Service Areas

Communication Medium	Target Audience	Budget
Bill Insert	All MO Electric Customers	$7,000
Informational Video	All MO Electric Customers	$3000
Website Landing Page	All MO Electric Customers	$0
Customer Email	All MO Electric Customers	$0
Social Media – Boosted	Select communities in service areas	$1000
Digital Campaign – 60 days	Select communities in service areas	$7500
Radio Spot – 60 days (production & schedule)	Select communities in service areas	$40,000
Total		**$58,500**

Figure 9

TOU Subscription Program

Target Audience: 50,000 customers (Liberty's AMI Sector 1 & 2: Joplin / Webb City / Carl Junction)

First year subscription Goal: 700

Communication Medium	Target Audience	Budget
Customer Survey	Sector 1 & 2	$5,000
Direct Mail	Sector 1 & 2	$37,500
Informational Video	Sector 1 & 2	$3000
Website Landing Page	Sector 1 & 2	$0
Targeted Digital Campaign – 60 days	Sector 1 & 2	$3,000
Customer Email	Sector 1 & 2	$0
TV Spot – 60 days (production & schedule)	Sector 1 & 2	$30,000
Radio Spot – 60 days (production & schedule)	Sector 1 & 2	$20,000
Total		**$98,500**

Q. Please describe EXP ADJ 14 for the TOU educational costs.

A. EXP ADJ 14 adjusts the requested cost of service to educate customers about the Company's proposed TOU program as described above. This results in a Total Company pro forma adjustment of $157,000 and a Missouri pro forma adjustment of $139,827 being included in the cost of service for the Company's educational campaign.

Q. Please describe EXP ADJ 26 for the AMI Project.

A. EXP ADJ 26 reflects the O&M expenses related to the Itron service contracts for the AMI Project. This results in an increase to Missouri expenses by $1,205,127.

Q. Please describe EXP ADJ 29 for AMI Meter Readers.

A. EXP ADJ 29 reflects the estimated reduction of $1,005,247 in contracted meter reader expenses expected to occur by the time new rates are in effect. This results in a Missouri pro forma ending balance of $0 for the contracted meter reader expense. After deployment of the AMI Meters, the Company plans to retain four employees to read meters manually where necessary.

Q. What is the annual revenue requirement impact related to AMI?

A. The annual revenue requirement for the AMI project included in the calculation of base rates in this cause is $7,382,687. The calculation of the AMI revenue requirement is shown in Figure 10 below.

Figure 10

The Empire District Electric Company Test Year Ending September 30, 2020 ER-2021-0312 Schedule 1 - AMI Revenue Requirement Summary			
Line No.	Description	Reference	Total Missouri Pro Forma Balance
	(a)	(b)	(c)
1	Rate Base	Schedule 2	$ 43,479,662
2	Revenues		286,200
3	Expenses		3,366,809
4	Operating Income (Loss) Before Taxes	(Line 2 - Line 3)	(3,080,609)
5	Effective Tax Rate	Schedule 4	23.84%
6	Income Taxes	(Line 4 x Line 5)	(734,420)
7	Operating Income (Loss) After Taxes	(Line 4 - Line 6)	(2,346,189)
8	Current Rate of Return	(Line 7 / Line 1)	-5.40%
9	Rate of Return Requested	Schedule 4	7.03%
10	Required Net Operating Income	(Line 1 x Line 9)	3,058,489
11	Income Deficiency	(Line 10 - Line 7)	5,404,678
12	Gross Revenue Conversion factor	Schedule 5	1.3130
13	Revenue Deficiency	(Line 11 x Line 12)	7,096,487
14	**Revenue Requirement**	(Line 2 + Line 13)	$ 7,382,687

VII. CONCLUSION

Q. Please summarize the Company's request for the above investments you describe.

A. The Company is requesting inclusion of the revenue requirements as described for each of the three investments, Wind Projects, Asbury Plant and AMI Project. As described above and in the Direct Testimonies of other Company witnesses, these assets and their produced treatment generate significant benefits for the Company's customers. Most importantly,

they represent a clear example of a technological and customer-focused strategic and operational pivot that Empire is in the process of making to better serve its customers.

Q. Does this conclude your Direct Testimony?

A. Yes.

VERIFICATION

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

/s/ Tisha Sanderson