FILED
October 30, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	CAUSE NO. 45253

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

REDACTED TESTIMONY OF

ANTHONY A. ALVAREZ – PUBLIC'S EXHIBIT NO. 5

OCTOBER 30, 2019

Respectfully submitted,

Scott Franson
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[redacted] (REDACTED) TESTIMONY OF OUCC WITNESS
ANTHONY A. ALVAREZ
CAUSE NO. 45253
DUKE ENERGY INDIANA, LLC

NOTE: [redacted] INDICATES CONFIDENTIAL INFORMATION

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Anthony A. Alvarez, and my business address is 115 West Washington Street, Suite 1500 South, Indianapolis, Indiana 46204.

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

A: I am employed as a Utility Analyst in the Electric Division of the Indiana Office of Utility Consumer Counselor ("OUCC"). I describe my educational background and preparation for this filing in Appendix A to my testimony.

Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A: Yes. I have testified in a number of cases before the Commission, including electric utility base rate cases; environmental and renewable energy Purchase Power Agreement ("PPA") and tracker cases; Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") cases; and applications for Certificates of Public Convenience and Necessity.

Q: What is the purpose of your testimony?

A: My testimony addresses Duke Energy Indiana, LLC's ("DEI" or "Petitioner") request for approval of the following proposals:

1. DEI generating fleet operation and maintenance ("O&M") expenses, including costs associated with periodic or cyclical generating facility major outages, except for the Edwardsport Integrated Gasification Combined Cycle ("Edwardsport" or "IGCC") plant;

2. O&M and capital expenditures, including costs associated with Edwardsport's major maintenance outage in 2020;

3. Integration and planned in-service costs for the Naval Support Activity ("NSA") Crane ("NSA Crane" or "Crane") microgrid and battery energy storage system ("BESS") projects in 2020; and

4. Major storm costs and reserves.

Ultimately, I recommend:

1. Normalizing O&M expenditures for DEI's generating facilities, including the cyclical maintenance outages. Using a seven-year average methodology to normalize the O&M expenses, including the associated major outage costs, I recommend an $80 million adjustment. This reduces DEI's generating facilities' forecasted Test Year O&M expenses to $149 million.

2. The Commission requires DEI adopt a seven-year average methodology to normalize Edwardsport's overall O&M Expenditures, Major Outage Expenses, and Miscellaneous Administrative and General Benefits ("Misc. A&G") costs in 2020. Groups within Duke corporate headquarters forecasted and attributed these costs to Edwardsport. I recommend adjusting the Edwardsport O&M, Major Outage and Misc. A&G expenses to decrease the forecasted 2020 Test Year to an overall total of $61.87 million.

3. A $10 million adjustment (including AFUDC) to remove capital expenditures, including all O&M expenditures associated with DEI's solar and BESS interconnection projects, from the forecasted Test Year.

4. The Commission set the initial Major Storm Reserve amount at $6 million and adopt the attendant mechanism of recording over and under revenue collection in the reserve account. Accordingly, I recommend a $6.7 million decrease to forecasted Test Year Major Storm Reserve. DEI must develop an operational plan to manage storm restoration activities prudently, with a set goal of decreasing the storm reserve to $6 million. DEI will incorporate the developed major storm operational plan within its vegetation management and TDSIC programs to ensure integration of the prescribed goals in these programs.

Q: What DEI cost data did you review in preparation of your testimony in this proceeding?

A: I reviewed DEI's generating facilities' confidential fixed O&M ("FOM") cost data contained in its 2018 Integrated Resource Plan ("IRP") dated July 1, 2019.[1]

Q: Is DEI's 2018 IRP cost data pertinent to this proceeding?

A: Yes. In developing its "preferred moderate IRP portfolio" DEI reflected FOM cost data for each generating unit.[2] The cost data DEI used for generating units in its 2018 IRP is germane to this case because it is consistent with DEI's preferred portfolio, as discussed by Petitioner's witness Mr. Keith B. Pike, Direct at 2, lines 18 – 21.[3] Additionally, Mr. Pike testifies, "[t]he implementation of the IRP preferred portfolio promotes a transition to enhanced generating fleet diversity and reduced risk exposure for Duke Energy Indiana customers."[4] Moreover, DEI filed its Petition in this proceeding on July 2, 2019, a day after it filed its 2018 IRP.

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with the DEI's proposal for that item?

A: No. Excluding discussion of any specific adjustments or amounts DEI proposes does not indicate my approval, but rather the scope of my testimony is limited to the specific items addressed herein.

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[1] Cause No. 45253, Direct Testimony of Stan C. Pinegar, Revised Petitioner's Exhibit 1, at 25, line 18, stated "[t]he company's preferred moderate IRP portfolio filed on July 1, 2019…" *See also* Petitioner's Administrative Notice Motion in this Cause filed on July 2, 2019.

[2] Pinegar, Direct at 25, lines 18, identified the "preferred moderate IRP portfolio."

[3] My testimony focuses on the 2018 IRP Cost Data of Duke's generation units Edwardsport. I did not review or analyze the entire IRP and did not need to in order to reach my conclusions in this testimony.

[4] Cause No. 45253, Direct Testimony of Keith B. Pike, Petitioner's Exhibit 15, at 3, lines 1 – 4. *See also* Pike, Direct at 13, footnote 3, for the webpage link to DEI 2018 IRP: https://www.duke-energy.com/home/products/in-2018-irp-stakeholder.

II. POWER PRODUCTION O&M EXPENDITURES

Q: Did you review DEI's power production O&M expenditures, associated with its generating facilities, in preparation of your testimony?

A: Yes. I reviewed power production O&M expenditures associated with the following DEI generating facilities:[5]

a. Cayuga
b. Gallagher
c. Gibson
d. Henry County
e. Madison
f. Markland Hydro
g. Noblesville
h. Vermillion
i. Wheatland

I reviewed non-fuel O&M expenses and O&M expenses related to these generators' outages ("outage expense").[6] The base cost of power production O&M expenses includes reagents and chemicals necessary to operate these generators in compliance with environmental regulations. Discussions related to reagents and chemicals, including compliance with environmental regulations, are beyond the scope of my testimony. OUCC witness Cynthia M. Armstrong discusses environmental related issues in her testimony.

Q: What is the total power production O&M expenditures DEI is proposing to include in the 2020 forecasted Test Year?

A: DEI proposes to include $229 million of power production O&M expenditures in the 2020 forecasted Test Year, for the nine generating facilities I identified earlier.[7] DEI's 2020 forecasted Test Year O&M expenses include $197 million of non-

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[5] I discuss my review of the Edwardsport IGCC fixed O&M expense later in my testimony, p. 9.
[6] Cause No. 45253, Direct Testimony of James Michael Mosley, Petitioner's Exhibit 19, at 29, Table 10 and lines 12 – 16.
[7] *Id.*

outage and $32 million outage-related O&M expenses. A generating unit's non-outage O&M expenses are typically flat year-to-year and periodically punctuated with outage-related expenses, based on the maintenance cycle of the generating unit.

The primary driver of planned major outages, and associated outage-related expenses, is the major turbine inspection. This inspection normally occurs about every seven years, based on actual hours of operation.[8] DEI witness James Michael Mosley testified that DEI performed (or plans to perform) major outage work on all nine of the above-named generating units during 2018 – 2020.[9] The total cost in outage-related O&M expenses for all nine generating units is $70 million. This amount is based on $11 million actual (2018), $27 million budgeted (2019), and $32 million forecasted (2020).[10]

Q: Do you agree with DEI's proposal to embed $32 million in base rates for outage-related O&M expenses?

A: No. DEI greatly overstated the $32 million annual outage-related O&M expenses it requested, as it does not represent the typical year of power production and operation with cyclic major maintenance outages. Since all DEI performed, or plans to perform, major outage work on all nine units in 2018-2020, there should be no scheduled major outages for 2021, 2022, 2023, and 2024 (based on a normal seven-year cycle). If the Commission approves embedding $32 million for outage-related

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[8] Mosley, Direct at 30, lines 19 – 22, stated "[o]ur goal, as represented by the 2019 and the 2020 outage O&M expense estimate, is to get back to having one or two major outages per year among the seven large coal units (Cayuga and Gibson), with the smaller availability outages filling out the rest of the schedule." *See also* Cause No. 45253, Direct Testimony of Mr. Cecil T. Gurganus, Petitioner's Exhibit 20, at 21, lines 13 – 15.
[9] Mosley, Direct at 31, lines 3 – 8.
[10] Mosley, Direct at 29, Table 10, line 11.

O&M expenses in base rates, DEI will continue to collect $32 million in four of the seven years where there are no scheduled major outages; essentially over-collecting $128M over the seven year period 2018-2024.

Additionally, if DEI performs scheduled major outage repairs on all nine facilities within a three-year period (2025–2027) following the seven-year cycle (2018-2024), DEI's proposal to embed $32 million in annual outage-related O&M expenses would result in DEI recovering $96 million over that three-year period. This is $26 million more than the $70 million DEI spent (or plans to spend) on major outage-related O&M expenses for the three-year period 2018–2020.

Q: What do you recommend regarding DEI's generating facilities' total power production O&M expenditures (outage and non-outage) for the 2020 forecasted Test Year?

A: I recommend normalizing power production O&M expenses associated with DEI's generating facilities and adopting a seven-year average methodology to reflect both non-outage and cyclical outage O&M expenses in the 2020 forecasted Test Year.[11] I also recommend using the power production O&M cost data found in DEI's 2018 IRP because it is part of the current information and DEI relied upon to keep its "long-term plan updated."[12] Further, DEI states in its 2018 IRP Summary, "[w]hen it is time to make a near-term decision, we gather the best available information to analyze for that specific decision in detail at that time."[13] Because DEI gathered "the best available information to analyze," it is also the best available data and

[11] The seven-year average methodology reflects a similar Duke seven-year amortization proposal for the Edwardsport IGCC major outage expense. *See* Gurganus, Direct at 26, lines 1 – 10.

[12] DEI 2018 IRP Summary, p. 3. Webpage: https://www.duke-energy.com/ /media/pdfs/for-your-home/indiana-irp/2018-dei-irp-summary-v5.pdf. Accessed: 10/02/2019.

[13] *Id.*

information to use in analyzing the cost of operating DEI's generation assets on a going-forward basis. Moreover, as stated in DEI's 2018 IRP Summary, "[a]fter comparing the expected cost of each portfolio under a variety of scenario assumptions, we [DEI] selected the Moderate Transition portfolio for the 2018 IRP."[14] I use the same cost data DEI provided in its 2018 IRP Moderate Transition Portfolio to normalize power production O&M expenses for DEI's generating assets. DEI states, "This portfolio benefits from a diverse generation mix as well as the ability to respond to emerging regulations."[15] Therefore, it is reasonable to expect the same benefits from my analysis.

Q: What is the total power production O&M expenditures you recommend the Commission allow DEI to embed in base rates?

A: I recommend DEI embed $149 million power production O&M expenses in base rates. This is an $80 million reduction to DEI's proposed 2020 forecasted Test Year power production O&M expenses of $229 million, and reflects a reduction in DEI's proposed annual non-outage O&M expenses from $197 million to $129 million and a reduction in DEI's proposed annual outage-related O&M expenses from $32 million to $20 million. My recommended non-outage O&M expenses is derived from DEI's own IRP assumptions and is conservative in that FOM considers <u>both</u> non-outage and outage O&M expenditures. Additionally, my recommended $149 million seven-year average outage-related O&M expenses allows DEI to sustain normal cyclic maintenance outages plus recover an additional

[14] *Id*.
[15] *Id*.

amount to insure against unanticipated major outage expense. Any amount above $149 million per year is unnecessary and unreasonable.

Q: Please summarize the results of your review and analysis supporting your recommendation.

A: DEI's IRP refers to the generating assets' fixed operations and maintenance as "FOM". It is essentially the combined outage and non-outage O&M expense. DEI used that FOM data to develop the preferred portfolio in its 2018 IRP reference case scenario. I focused my analysis on the cost data for the period 2018 through 2026. The cost data includes forward-looking years prior to DEI's next major outage in 2027. To calculate the $149 million seven-year average FOM, I took the FOM for forecasted years 2020-2026 and adjusted these annual amounts to reflect the seven-year amortization of major outage costs.

Since DEI performed, or plans to perform, its major outage work over a three-year period, I normalized the three-year outage O&M costs shown in Table 10 of Mr. Mosley's testimony by adding the costs in years 2018-2020 ($70 million) to represent the cyclic maintenance outage over seven years. I applied a factor of two ($70 million x 2 = $140 million) to cover the costs of any unexpected events similar to the turbine failure at Cayuga in Oct. 22, 2014,[16] or major turbine overhauls needed sooner due to higher operating hours that could happen within a seven-year period. I then amortized the resulting total over the seven-year period 2020-2026 ($140 million ÷ 7 years = $20 million per year).

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[16] *See* Coal Inventories Climb Again, Coal 'decrement' Stages a Comeback At Duke Energy Indiana Barry Cassell - https://www.transmissionhub.com/articles/2015/07/coal-inventories-climb-again-coal-decrement-stages-a-comeback-at-duke-energy-indiana html. Accessed: 10/27/2019.

To derive the Total FOM per year, I added the seven-year amortization major outage expense of $20 million per year to the FOM cost for each year of the 2020-2026 period. I summed the Total FOM costs of each year for 2020-2026 and divided the total sum by seven to determine the seven-year average FOM costs, which is the recommended $149 million level of total power production O&M expenses to include in DEI's 2020 forecasted Test Year. Table 1 below summarizes the power production O&M expenses cost data I used in my analysis.

Table 1: Generating Assets O&M and Major Outage Costs Data 2020 - 2026, $ in millions

	2020[3]	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
A. 2018 IRP Cost Data							
Fixed O&M, FOM[1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Major Outage[2]	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Total FOM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7-Year Average FOM 2020 – 2026[4]	$149.00						

	2018	**2019**	**2020**	**Total**	**Factor 2x**	**7-Year Amort.**
B. Major Outage Cost						
Major Outage	$11.00	$27.00	$32.00	$70.00	$140	$20.00

[1] *FOM Cost Data of Preferred Portfolio in Reference Case Scenario, DEI 2018 IRP.*
[2] *7-Year Amortization = ($70M x 2) / 7 years.*
[3] *Forecasted Test Year.*
[4] *7-Year Average O&M Expenses Forecasted Test Year.*

The FOM cost data in Table 1 is the total annual FOM cost of the nine DEI generating facilities I identified at the start of this section as reflected in the 2018 IRP. By taking into consideration DEI's seven-year cyclical maintenance schedule, it would be appropriate to use a seven-year average methodology to normalize the generating facilities' power production O&M expenses.

III. EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE ("IGCC") GENERATING FACILITY

Q: What does DEI propose to include in base rates for Edwardsport O&M expenditures?

A: DEI requests to embed $112.7 million of annual Edwardsport O&M expenditures in base rates. Petitioner's witness Mr. Cecil T. Gurganus testified the total O&M expense of Edwardsport, reflected in DEI's 2020 forecasted Test Year, is $145.8 million.[17] However, in calculating the proposed base rate amount, DEI's 2020 forecasted Test Year amount was reduced my $46.4 million associated with a major outage planned for 2020.[18] Mr. Gurganus also amortized the major outage cost for seven years to reflect the 7-year cyclical major outage schedule of Edwardsport, and included miscellaneous administrative and general expenses to derive the embedded test year amount. Table 4 below summarizes DEI's proposed amount to embed in base rates for Edwardsport O&M expense, as proposed by Mr. Gurganus.[19]

Table 4: DEI Proposed Edwardsport O&M Expense Base Rate Amount Calculation, $ in millions

		2020
Total O&M Expense Forecast		$145.8
Less: Major Outage Cost		(46.4)
	Sub-Total	$99.4
Add: Major Outage 7-Year Amortization		6.6
	Sub-Total	$106.0
Add: Misc. A&G Cost		6.7
	Total	$112.7

[17] Cause No. 45253, Direct Testimony of Mr. Cecil T. Gurganus, Petitioner's Exhibit 20 at 16, lines 17 – 18.
[18] Gurganus, Direct at 16, lines 18 – 19.
[19] *Id*.

At this level of expense, Edwardsport's ongoing maintenance cost is excessive and unreasonable for 618 MW of capacity. DEI's Gibson generating station, which is four-and-a-half times its size and capacity at 2,845 MW, has comparable O&M costs.[20] All else equal, Edwardsport cannot operate economically using coal when its O&M costs are four-plus times greater than DEI's other coal plants.

Q: What amount do you recommend be embedded in base rates for Edwardsport O&M expenditures?

A: Based on my review, I recommend $61.87 million in Edwardsport O&M expenditures be embedded in base rates. This is an approximate $50.83 million reduction to DEI's proposed $112.7 million. I derive my recommendation from DEI's historical actual amounts and IRP cost data.

Q: Please describe your review of DEI's Edwardsport O&M expenditures in deriving your recommended base rate amount.

A: I reviewed the Edwardsport O&M expenditure actual amounts for 2013 through 2018, and projected amounts for 2019 and 2020.[21] I reviewed the 2016 Edwardsport Settlement Agreement ("2016 IGCC Settlement") approved by the Commission in Cause No. 43114 IGCC-15, dated August 24, 2016, and the 2018 Edwardsport Settlement Agreement ("2018 IGCC Settlement") approved by the Commission in Cause No. 43114 IGCC-17, dated June 5, 2019.[22] In the 2016 IGCC Settlement, the O&M Expenditure Caps ("O&M Caps") were $73.3 million in 2016 and $76.8

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[20] Cause No. 45253, OUCC Attachment AAA-1 – DEI's Response to IG DR Set 17.1 (a) – (c), Attachment IG-17.1-A.
[21] Cause No. 45252, OUCC Attachment AAA-2 – DEI Response to IG DR Set 2.11(e).
[22] IURC Order in Cause No. 43114 IGCC-15 dated August 24, 2016 ("IGCC-15 Order"); and IURC Order in Cause No. 43114 IGCC-17 dated June 5, 2019 ("IGCC-17 Order").

million in 2017.[23] In the 2018 IGCC Settlement, the O&M Caps were $97.6 million in 2018 and $96.0 million in 2019.[24] I also reviewed the Edwardsport Capital Expenditure Caps of $36.1 million in 2016 and $16.9 million in 2017, defined in the 2016 IGCC Settlement.[25]

I reviewed Edwardsport's confidential fixed and variable O&M data found in DEI's 2018 IRP dated July 1, 2019. I also reviewed publicly available data and statistics for Edwardsport found in DEI's FERC Form 1 and EIA-923 reports and filings.[26]

Q: Please discuss your review of Edwardsport's actual, projected and forecasted O&M expenditures for 2013 through 2020 relative to the IGCC Settlement O&M Caps.

A: Through rates, DEI recovered Edwardsport's actual O&M expenditures incurred in 2013, 2014 and 2015, albeit subject to the provisions of the 2012 IGCC Settlement Agreement.[27] However, DEI's recovery of Edwardsport's O&M expenses during the period 2016 through 2018 and projected in 2019, were subject to O&M Caps under the provisions of the 2016 and 2018 IGCC Settlements.[28] Table 2 below summarizes Edwardsport's actual O&M expenditures from 2013 through 2018, projected in 2019, and forecasted in 2020, including the cost of the major outage in 2020.

[23] IGCC-15 Order at 80.
[24] IGCC-17 Order at 17.
[25] IGCC-15 Order at 81. The Cap amount of $36.1 million in 2016 includes ongoing capital additions from April 1, 2015 through December 31, 2016.
[26] Federal Energy Regulatory Commission Form No. 1 ("FERC Form 1"). Website: https://www.ferc.gov/docs-filing/forms/form-1/data.asp. Accessed: 09/30/2319.
[27] IGCC-15 Order at 31.
[28] *See* IGCC-15 Order at 80 and IGCC-17 Order at 81.

Table 2: Edwardsport IGCC Actual and Projected O&M Expenditures 2013 – 2020, $ in millions[29]

	2013	2014	2015	2016	2017	2018	2019	2020
Actual O&M Expense[1]	$39.3	$70.9	$95.2	$132.3	$110.1	$103.1	$106.4	$105.1
2020 Major Outage	-	-	-	-	-	-	-	46.4
Total	$39.3	$70.9	$95.2	$132.3	$110.1	$103.1	$106.4	$151.6

Source: DEI Response to Industrial Group ("IG") Discovery Set 2.11(e).
[1] Projected (2019) and Forecasted (2020).

Due to the O&M Caps in the 2016 and 2018 IGCC Settlements, DEI could not recover from ratepayers the Edwardsport actual O&M expenditures in excess of the O&M Caps in 2016, 2017, 2018 and projected for 2019. Table 3 below compares the Edwardsport actual and projected O&M expenditures and O&M Cap amounts for the period 2016 through 2019.

Table 3: Actual and Projected O&M Expenditures vs O&M Caps 2016 – 2019, $ in millions

	2016	2017	2018	2019
Actual & Projected O&M Expense[1]	$132.3	$110.1	$103.1	$106.4
O&M Cap	73.3	76.8	97.6	96.0
Disallowance	$59.0	$33.3	$5.5	$10.4

[1] Projected (2019)

In each year an O&M Cap was in place, Edwardsport operations consistently exceeded the cap. In 2018, when the O&M Cap increased by 27.1% from the previous year, Edwardsport operations still exceeded the cap, projected an increase to its operational expenses the following year (2019), and expected to incur a higher disallowance in 2019.

[29] OUCC Attachment AAA-2. Projected in 2019 and forecasted in 2020 including major outage costs.

Q: Mr. Gurganus shows the 2019 Budget for Edwardsport O&M expense decreased and saved ratepayers $3 million as compared to the $99 million actual expense in 2018.[30] Based on your analysis, have Edwardsport O&M expenses decreased when comparing 2018 actual to 2019 budgeted?

A: No. As shown in my Table 3 above, actual and projected O&M expenses of Edwardsport operations did not decrease in 2019 and without the O&M Cap in place would not provide any savings to ratepayers. Mr. Gurganus' analysis reflected the IGCC Settlement O&M Cap for 2019 and compared it with an understated actual 2018 expense to show a decrease in 2019 Edwardsport O&M expense and savings of $3 million, when in fact, O&M expense actually increased and there were no savings at all. Without the O&M Cap in place for 2019, ratepayers would be responsible for an additional $9 million in 2019 as compared to 2018 ($106.4 in 2019 less $97.6 million in 2018). Since 2015, the actual O&M expenses of Edwardsport operations have not fallen below $100 million, as shown in my Table 3 above.

Q: Mr. Gurganus testified, "Edwardsport's actual O&M expense for 2018, 2019 budget and 2020 forecast are actually on a slightly declining trend."[31] Do you agree with this statement?

A: No. There is no declining trend in the Edwardsport operation's O&M expenses. Any cost decrease afforded to ratepayers resulted from O&M Caps imposed by previous IGCC Settlement Agreements, and not from Edwardsport operations. Nevertheless, despite the incentive signals of the O&M Caps embedded in previous IGCC Settlement Agreements, Edwardsport operations continue to run the facility

[30] Gurganus, Direct at 17, Table 1.
[31] Gurganus, Direct at 17, Table 1.

at a high level of operating costs—in excess of $100 million annually.[32] There are no O&M Caps in place beyond 2019.

Q: Mr. Gurganus, Direct at 18, lines 6 – 9, claims, absent the major outage cost in 2020, Edwardsport operations have "keenly focused on reducing O&M."[33] Has DEI's keen focus on O&M expenditures since 2017 achieved significant expense reduction?

A: No. Edwardsport operations have not achieved any significant expense reductions. In 2017, the $76.8 million O&M Cap caused DEI shareholders to absorb $33.3 million for Edwardsport's O&M expenses. During 2016, DEI's shareholders absorbed $59.0 million for Edwardsport's O&M expenses due to that year's $73.3 million O&M Cap. In 2018, despite the relief of an increased O&M Cap to $97.6 million, Edwardsport operations still caused DEI shareholders to absorb another $5.5 million in O&M expenses. Relying on Mr. Gurganus' numbers, in 2019, DEI shareholders will again face an additional $10.4 million of O&M expenses it cannot pass on to ratepayers, because of a $96.0 million O&M Cap.[34] By the end of 2019, O&M Caps for the period 2016-2019 will have saved ratepayers $108.2M. Despite the O&M Caps and the almost-certain internal pressure from DEI shareholders for the losses it absorbed, Edwardsport operating costs remain excessive, especially when compared to the operating costs DEI projected when they sought approval to build this plant.[35]

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[32] Based on fixed O&M costs compared with other DEI coal-fired power plants. *See* OUCC Attachment AAA-1.
[33] Gurganus, Direct at 18, lines 6 – 9.

[34] Mr. Gurganus provided the data in DEI's Response to IG DR Set 2.11(e). *See* OUCC Attachment AAA-2.
[35] Cause No. 43114, Rebuttal Testimony of Stephen M. Farmer, (Confidential) Petitioner's Exhibit No. 28-E, Line 39, Columns AC and AD, p. 7 of 15.

Q: Does DEI's 2018 IRP consider Edwardsport for retirement?

A: No. DEI does not consider Edwardsport for retirement in the IRP because it "is the newest on our [DEI] system," it "has the longest estimated life (2045)," "successfully improved operations in the past several years," focus "on reducing its ongoing maintenance costs," and contribute "to the fleet's diversity."[36]

Q: Aside from the estimated life of Edwardsport lasting beyond the 2018 IRP planning horizon, did the IRP take into account a realistic forecast of the IGCC's expense?

A: Yes. The IRP took into account one crucial element regarding Edwardsport in its review—it assumed Edwardsport "*going forward will be focused on reducing its ongoing maintenance costs*."[37] By doing so, DEI's IRP forecasted the fixed and variable O&M expense of Edwardsport at an optimal level based on the belief that "[t]he plant has successfully improved operations over the past several years."[38] With critical insights into the finance, dispatch, operations and management of its own generating resources, future energy and capacity needs, by employing quantitative analysis to gain insights on future risks and uncertainties, and qualitative considerations on such important factors like fuel diversity, the resulting resource plan provided DEI with an important guide for making business decisions.[39] Part of that business decision is a realistic and unique insight of Edwardsport's overall future operations and performance. "Based on its superior

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[36] "The Duke Energy Indiana 2018 Integrated Resource Plan," July 1, 2019, Volume 1, pp. 58 – 59. Website: https://www.duke-energy.com/_/media/pdfs/for-your-home/indiana-irp/duke-energy-indiana-public-2018-irp.pdf. Accessed: 09/28/2019.

[37] DEI 2018 IRP, p. 59.

[38] *Id*.

[39] DEI 2018 IRP, p. 4.

performance in scenario and sensitivity analyses" DEI selected the Moderate Transition Portfolio as its 2018 IRP preferred resource plan.[40] Embedded in that preferred resource plan is Edwardsport's cost forecast for the review period of the 2018 IRP. DEI filed its case-in-chief on July 2, 2019, one day after submitting its 2018 IRP with the Commission. The 2018 IRP reflects Edwardsport cost forecast and DEI's latest cost data and management insights of the generating plant's current and future operational performances.

Q: Please describe your review of DEI's cost forecast of Edwardsport's overall future operational performance.

A: I reviewed Edwardsport FOM data used by DEI in developing the preferred portfolio, in the reference case scenario, for the period 2018 through 2037, in its 2018 IRP. I focused my review on the period 2018 through 2026 including the costs from the historic test period 2018, projected 2019, forecasted Test Year 2020, and the forward-looking years prior to the next major outage in 2027 ("forecast years"). I made adjustments to incorporate the major outage cost seven-year amortization in the cost data of my analysis. I modeled both a nine-year average and seven-year average costs to determine the reasonable level of FOM (non-fuel) expenses of Edwardsport to include in the future Test Year. I compared the results of my analysis with "Edwardsport IGCC Unit Specification Summary" document provided by DEI in its response to IG DR Set 8.3(b), Confidential Attachment IG

[40] DEI 2018 IRP, p. 19.

8.3-A.[41] Table 5 below summarizes Edwardsport FOM cost data used in my analysis.

Table 5: Edwardsport IGCC Fixed O&M and Major Outage Costs Data 2018 - 2026, $ in millions

	2018	2019	2020[3]	2021	2022	2023	2024	2025	2026
A. 2018 IRP Cost Data									
Fixed O&M, FOM[1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9-Year Average FOM 2018 – 2026[2]			$60.12						
7-Year Average FOM 2020 – 2026[4]			$54.99						
B. 2018 Actual, 2019 Projected, 2020 Forecasted, and 2018 IRP Cost Data (2021-2026)									
Fixed O&M, FOM[5]	$103.10	$106.40	$105.10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Major Outage[6]	0.0	0.0	$6.63	$6.63	$6.63	$6.63	$6.63	$6.63	$6.63
Total FOM	$103.10	$106.40	$111.7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9-Year Average Total FOM 2018 – 2026[2]			$66.24						
7-Year Average FOM 2020 – 2026[4]			$61.87						
C. Confidential Attachment IG 8.3-A									
Fixed O&M, FOM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9-Year Average FOM 2018 – 2026[2]			$68.71						
7-Year Average FOM 2020 – 2026[4]			$64.99						

[1] FOM Cost Data of Preferred Portfolio in Reference Case Scenario, DEI 2018 IRP. Includes Major Outage cost in 2020.
[2] 9-Year Average Methodology, 2018 – 2026.
[3] Cost includes Major Outage unless otherwise indicated.
[4] 7-Year Average Methodology, 2020-2026. Includes Major Outage cost in 2020.
[5] FOM Cost Data 2018 – 2020 in DEI response to IG DR Set 8.11.(e); FOM Cost Data 2021 – 2026 in DEI 2018 IRP.
[6] Major Outage Cost $46.4 million amortized in 7 years (per DEI proposal).

Q: What are the results of your review of DEI's cost forecast?

A: The cost data sets (A), (B) and (C), in Table 5 incorporated the Edwardsport major outage cost in 2020. The nine-year cost average is higher than the seven-year cost average because it includes two additional years of historical costs (2018 and 2019) and overstates the 2020 forecasted Test Year, which already considered such costs. Likewise, embedding a single-year expense forecast in future rates would be counter-productive in the case of Edwardsport, because it would only perpetuate

[41] Cause No. 45253, Confidential OUCC Attachment AAA-3C – DEI Response to IG DR Set 8.3 (b), Confidential Attachment IG 8.3-A.

unreasonable and excessive operating costs going forward, provide operations with no incentive to improve future operating performance, and dissuade management from reducing its ongoing maintenance costs. Taking into consideration its seven-year cyclical maintenance schedule, it would be appropriate to use a seven-year average methodology to normalize the Edwardsport IGCC fixed O&M and major outage expenses.

Q: What do you recommend regarding Edwardsport O&M expenditures?

A: As stated previously in my testimony, I recommend Edwardsport O&M expenditures of $61.87 million be embedded in base rates. To achieve this, I recommend the Commission require DEI to adopt a seven-year average methodology to normalize Edwardsport overall O&M Expenses, Major Outage Expenses, and Misc. A&G costs (forecasted and attributed to Edwardsport by other corporate groups) in 2020 as shown in Table 5, Section B.

IV. MAJOR STORM RESERVE

Q: What does DEI propose regarding major storm expense and damage restoration reserve?

A: DEI requests to embed $12.7 million in base rates for major storm expenses and establish a Major Storm Damage Restoration Reserve ("Major Storm Reserve") to track major storm expenses over and under the normalized amount of $12.7 million.[42] DEI will record any major storm expense under-recovery as Regulatory Asset and any over-recovery as Regulatory Liability.[43] DEI proposes to address the

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[42] Cause No. 45253, Direct Testimony of Suzanne E. Sieferman, Petitioner's Exhibit 5, at 33, lines 17 – 22 through p. 34, lines 1 - 4.

[43] *Id*.

recovery of any net amount in the Major Storm Reserve in the next retail base rate case.[44]

Q: Please describe your review of DEI's major storm expense and damage restoration reserve.

A: I reviewed the five-year historical average for major storm costs shown in DEI witness Susan E. Sieferman, Workpaper OM3-SES ("OM3-SES"), and her testimony related to Major Event Day ("MED"); the Institute of Electrical and Electronic Engineers ("IEEE") Standard 1366 ("IEEE Std. 1366"), and System Average Interruption Duration Index ("SAIDI") – a distribution performance metric – as related to IEEE Std. 1366-2012, MED Threshold (T_{MED}).[45] I reviewed Petitioner's witness Cicely M. Hart, Table 4, p. 11, showing the outage causes in DEI's distribution system; Table 8, p. 36, summarizing DEI's storm activity since 2014; and her testimony related to TDSIC and Vegetation Management expenditures.[46] OUCC witness Eric Hand addresses vegetation management in his testimony.

Ms. Sieferman's OM3-SES shows $11.2 million (88%) of major storm expenses were distribution operation related, $0.5 million (4%) were transmission related, and $1.0 million (8%) were benefits and taxes. Ms. Sieferman explained the relationships between the distribution performance index, SAIDI, and the IEEE

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[44] *Id*.
[45] *See* Ms. Sieferman, Workpaper OM3-SES filed in this Cause; and Direct at 34, lines 8 – 21, regarding IEEE Std. 1366, MED and T_{MED}.
[46] Cause No. 45253, Direct Testimony of Cicely M. Hart, Petitioner's Exhibit 26, at 11, for Table 4 showing outage causes and percent of each outage cause; Direct at 36, for Table 8 showing the storm level and the number of Major Event Days ("MED") for the period 2014 through June 9, 2019; Transmission, Distribution and Storage System Improvement Charges ("TDSIC"), pp. 3, 12 - 18, and 31; and Vegetation Management, pp. 16 – 17.

Std. 1366, MED and T_{MED}.[47] On any day wherein the severity of a storm causes the utility's SAIDI to reach or exceed T_{MED}, the utility declares that day a MED.[48] Ms. Sieferman testified the utility shifts into a crisis mode to respond adequately to the level of storm severity.[49]

Ms. Hart's Table 4 on p. 11, shows that in 2018, vegetation (29%) and equipment failures (22%) were the top two causes of outages and accounted for more than half (51%) of the outages in DEI's distribution system.[50] In addition, Ms. Hart's Table 8 on p. 36, illustrates the storm level severity effects on the number of Major Event Day ("MED") declared since 2014. She described the cost effects of major storm restoration, vegetation management and TDSIC projects on DEI's historical and forecasted O&M costs.[51] In addition, Ms. Hart, Direct at 18, lines 1 – 7, provided the TDSIC-related distribution capital expenditures of DEI's historical and forecasted capital expenditures. DEI's TDSIC expenditures were $142 million (42%) of $342 million total distribution capital in 2018, projected as $116 million (32%) of $363 million in 2019, and forecasted as $100 million (30%) of $332 million in 2020.[52]

Q: What are the results of your analysis regarding DEI's major storm expense and proposed Major Storm Reserve?

A: In general, a storm reserve is an accounting treatment that will smooth out the financial impacts of major storm restoration costs to ease the financial

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[47] Sieferman, Direct at 34, lines 13 – 19.
[48] IEEE Std. 1366.
[49] Sieferman, Direct at 34, lines 13 – 15.
[50] Hart, Direct at 10, lines 9 – 14.
[51] Hart, Direct, pp. 16 – 20.
[52] Hart, Direct at 12, lines 8 – 11.

consequences of a major storm.[53] The attendant mechanism to record the over and under collection of revenues in a reserve account provides a semblance of security that customers pay the reasonable costs of restoring power after a major storm and the utility recover its costs through rates. Interested parties retain the ability to scrutinize and given the opportunity to challenge the reasonableness of the storm expenses included in the reserve account in the utility's subsequent basic base rate case.[54] By establishing a storm reserve the Commission can consider and resolve issues, review revenues and expenses, and issues an order within the context of a rate case to adjust basic rates and closely align revenue recovery with the expected major storm expenses.[55] However, challenges remain in establishing the initial amount of major storm expenses, setting the level of major storm reserve and embedding in rates an incentive for the utility to manage prudently its expenses associated with major storms. Although "[t]he availability of a reserve does not remove or diminish the Company's separate obligation to reasonably establish the level of storm costs and to manage that expense,"[56] there is no assurance that the utility incurred its historical storm expenses from a prudent management of its storm expenses. Ratepayers require the assurance but DEI provided no evidence of such as I discuss later in my testimony. Therefore, there is a need to create an incentive for DEI to manage its system and major storm expenses with prudence.

[53] *See* generally, IURC Final Order in Cause No. 44075, for Commission discussion on Major Storm Reserve, February 13, 2013, Section 5 (f), pp. 72 - 73.
[54] *Id*.
[55] *Id*.
[56] *Id*.

Q: How do you propose to create and incorporate an incentive in DEI's proposed Major Storm Reserve?

A: To create the incentive, first, broaden the scope of DEI's major storm activities from a reactionary to a proactive nature; engage, coordinate and realign complementary programs and objectives, and lastly, develop an operational plan with the goal of substantially decreasing the level of storm reserve needed. To do so, I propose to engage DEI's vegetation management and TDSIC programs by coordinating and realigning their project objectives to include identifying and alleviating vulnerable circuits, lines, equipment and facilities in DEI's distribution and transmission system from extensive damage and prolonged outages during major storms. Operational efficiency dictates DEI recognize the benefits of coordinated programs and aligned objectives with the overall value added from resultant synergy of resources afforded to it by ratepayers. With the support of coordinated and aligned vegetation and TDSIC program objectives, DEI will develop an operational plan to manage storm restoration activities prudently with a set goal of decreasing the need to call for substantial additional resources from ratepayers, lowering the level of its proposed storm reserve amount to half, and increasing the efficiency and effectiveness of available operation resources. However, setting the initial level of major storm reserve remains crucial as this provides the incentive needed for DEI to develop an effective operational plan.

DEI provided clear evidence of vegetation and equipment failures as primary causes of distribution outages. Its TDSIC program accounted for more than a third of its historical and forecasted capital expenditures (2018-2020). Although ratepayers afforded DEI ample resources for vegetation management and

TDSIC programs to address the cause of outages, DEI distribution reliability metrics continued to show a deteriorating trend because DEI approached these programs from a technical and operational perspective.[57] For example, DEI's vegetation management employs a systematic method of clearing and cutting down of trees and vegetation along rights-of-way for operational efficiency. Further, DEI utilized highly technical statistics and probabilistic theories to rank the likelihood and consequence of failure to identify, inspection, replacement, and repair lines, equipment and facilities in the TDSIC program. While this appears logical, what is missing are the coordination, realignment and redirection of the program objectives towards identifying and targeting distribution and transmission circuits, lines, equipment and facilities vulnerable to extensive damage during, and prolonged outages after, major storms.

Q: Will the proposed operational plan divert vegetation management focus and resources from its original purpose?

A: No. DEI will continue clearing rights-of-way, trees, mowing down thick vegetation; chasing after emerald ash borers; cutting down hazard, dead and disease-ridden trees; and other typical vegetation management duties.[58] It will perform the same activities on facilities identified as vulnerable to extensive damage and prolonged outage after a major storm. At the onset, the location of the targeted facilities may be out of rotation and DEI must clear it ahead of its pre-set

[57] *See* IURC Electric Utility Reliability Report 2018. Website: https://www.in.gov/iurc/files/2018%20Reliability%20Report.pdf. Accessed: 09/26/2019.
[58] OUCC witness Eric Hand addresses DEI's vegetation management proposal.

vegetation-clearing schedule. However, afterwards, the cleared and freed facilities may fall into the vegetation clearing routine schedule.

Q: DEI identified the facilities and project work included in its TDSIC's original 7-Year TDSIC Plan filing. Will your proposed operational plan throw off its TDSIC schedule?

A: No. DEI has the freedom to move projects around, earlier or later, in its 7-Year Plan and would simply apply and perform the same TDSIC work scope on these vulnerable facilities. DEI could easily accommodate the remedial work needed to strengthen vulnerable facilities within the framework of its TDSIC Plan.

Q: Will the proposed plan burden DEI's operational management of storm restorations?

A: No. On the contrary, DEI may see positive results such as faster restoration times, less number of outages and declining trends in the extent of facility damages suffered during storms. This will be possible due to the proposed plan's proactive characteristic, coupled by the synergy from vegetation management and TDSIC coordinated programs and aligned objectives, with effective execution and proper management, in the long term. Overall, the proposed plan offers DEI the opportunity to address its declining distribution metrics, increase reliability and resiliency of its system, harness the potential benefits from realigning program objectives, lower the need for additional resources, lessen the burden on captive ratepayers, and take a proactive stance to achieve operational success in managing storm restorations.

Q: In Cause No. 45235, you advocated a 5-year methodology for determining the level of major storm reserve. Please explain why you are opposing the same methodology offered by DEI setting the initial level of major storm reserve.

A: In Cause No. 45235, the utility's major storm reserve was in its third generation of iteration.[59] The utility's five-year historic major storm expenses were subject to an over / under collection mechanism using a reserve account. Substantial evidence supported both actual storm expenses and importantly, the utility's prudent management of its storm expenses. Under those circumstances, I supported using five years' historic major storm expenses to determine the major storm reserve.

In this case, neither the $21.7 million (2018) nor the $12.7 million (5-year average) major storm expenses proposed by DEI were supported by evidence that they were incurred despite prudent management. DEI witness Ms. Hart's direct testimony, in Table 9 on p. 37, showed a significant increase in DEI's major storm expenses in 2016 compared to 2015. The 2018 IURC Electric Utility Reliability Report showed significant increases in DEI's SAIDI during normal days (without MED) and major event days (with MED) of operations in 2016, as compared to 2015. However, DEI experienced the fewest number of MED in 2016 during the five-year period 2014 through 2018. As accurately depicted by Ms. Sieferman, a MED signified the utility shifted "into a crisis mode of operation to adequately respond" to a major reliability event.[60] Accordingly, the utility shifts back into normal mode of operations during stable or normal operating days.

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[59] *See* IURC Final Orders in Cause No. 44075, (February 13, 2013) and Cause No. 44967, (approving Settlement) May 30, 2018.
[60] Sieferman, Direct at 34, lines 13 – 15.

In 2016, not only did DEI experience fewer MEDs, they also received its 7-Year Plan approval to spend hundreds of millions of dollars to improve its distribution and transmission through a TDSIC program.[61] Despite these favorable operation conditions with ample resource availability, DEI operations performed poorly marked by significant increases in major storm expense and SAIDI for both normal and crisis modes of operation. DEI's poor operational performance under favorable conditions raises questions whether DEI has the optimal operational plan in place to handle crisis conditions, and to manage major storms.

Q: Do you oppose establishing a Major Storm Reserve if DEI agrees to develop your proposed operational plan to manage major storm activities and expenses?

A: No. If DEI agrees to develop an operational plan based on the goals prescribed, I do not oppose establishing a Major Storm Reserve for DEI. In addition, DEI must incorporate the developed major storm operational plan within its vegetation management and TDSIC programs to ensure integration of the prescribed goals in these programs. I also recommend DEI maintain the same format used in Ms. Hart, Table 9, p. 36, to summarize major storm annual expenses and make it available in its next basic rates case. Under these conditions, I recommend the Commission allow DEI to establish a Major Storm Reserve mechanism with an initial Major Storm Reserve amount of $6 million. Alternatively, should the Commission deny DEI authority to establish a Major Storm Reserve mechanism, I recommend embedding $5 million in base rates to represent half of DEI's annual $10 million

[61] *See* Cause No. 44720, IURC Final Order, June 29, 2016 approving DEI's TDSIC 7-Year Plan.

O&M budget for storm expense (a reduction of $7.7 million from its 2020 forecasted Test Year storm expense amount).

Q: In addition to your recommendations regarding a Major Storm operational plan, please discuss your recommendation to the Commission in setting the initial level of Major Storm Reserve.

A: As discussed earlier, setting the initial amount for storm reserve is crucial in guaranteeing DEI has the incentive to develop an operational plan as prescribed. I recommend the Commission set the initial amount of Major Storm Reserve at $6 million and adopt the attendant mechanism of recording over and under collection of revenues in the reserve account. Accordingly, I recommend a $6.7 million decrease to forecasted Test Year Major Storm Reserve.

V. CRANE MICROGRID AND BESS

Q: What is DEI's proposal regarding the microgrid and BESS at NSA Crane.

A: DEI requests the approval include $10 million in base rates for the Crane microgrid.[62]

Q: Please describe your review of DEI's proposal regarding the microgrid and BESS at NSA Crane.

A: Petitioner witness Andrew S. Ritch characterized DEI's proposed "microgrid" as just the existing 17 MW Solar facility and proposed BESS (or "solar and battery").[63] However, there is no interconnected load or any operational control of the NSA Crane loads. This arrangement is not a microgrid. The Department of Energy ("DOE") defines the microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act[s]

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[62] Cause No. 45253, Direct Testimony of Andrew S. Ritch, Petitioner's Exhibit 24, at 8, lines 1 – 2.
[63] Ritch, Direct at 6, lines 16 – 18. Also, for brevity, the term "solar and battery" refers to the combination of the existing 17 MW Solar facility and proposed 5 MW BESS.

as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode."[64]

Instead of a "real" microgrid, DEI will actually use $10 million of ratepayer dollars to install a new 5-MW BESS facility, connect it with DEI's existing 17 MW Crane Solar facility, and with the Department of Navy ("Navy") planned microgrid installation at NSA Crane ("NSA Crane Microgrid").[65] DEI plans to place the proposed BESS project in-service in 2020.[66] Nonetheless, I analyzed and evaluated its request based on the benefits, if any, to DEI customers.

I reviewed the Commission's Final Order in Cause No. 44734, dated July 6, 2016, approving a settlement agreement and granting DEI a certificate of public convenience and necessity ("CPCN") for the 17 MW Crane Solar facility. In the Settlement Agreement, DEI agreed not to seek recovery from its customers any amount in excess of $400,000 for a remote operable switch and a feasibility study.[67] Mr. Ritch indicated that currently DEI has a tentative plan to install the remote operable switch in a future date.[68] I reviewed the "NSA Crane Microgrid Design Study" ("Microgrid Study") DEI provided in its confidential response to OUCC

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[64] Dan T. Ton and Merrill A. Smith, The U.S. Department of Energy's Microgrid Initiative, The Electricity Journal, 2012. Website: https://www.energy.gov/sites/prod/files/2016/06/f32/The%20US%20Department%20of%20Energy's%20Microgrid%20Initiative.pdf. Accessed: 09/23/2019. *See also* Microgrids at Berkeley Lab. Website: https://building-microgrid.lbl.gov/microgrid-definitions. Accessed: 09/23/2019.
[65] Ritch, Direct at 6, lines 8 – 10. *See also* CONFIDENTIAL "NSA Crane Microgrid Design Study" document ("Microgrid Study") prepared for Navy and DEI by Doosan GridTech, Seattle, WA, August 2018.
[66] Ritch, Direct at 5, lines 2 – 4.
[67] Cause No. 44734, Final Order, Section 5 – Settlement Agreement, para. 4, p. 16.
[68] Ritch, Direct at 5, lines 7 – 9.

DR Set 14.2-A.[69] Doosan GridTech ("Doosan") completed the microgrid study on August 30, 2018 for the Navy and DEI.[70] I also reviewed the Commission's Order in Cause No. 45002 dated May 30, 2018 on the Camp Atterbury Microgrid and Nabb Battery project relating to the issues of solar facility, battery storage and microgrid.[71]

Q: What is the current DEI utility service or feed to NSA Crane during normal operations and during a major bulk power system or grid outage event?

DEI has a [redacted] system serving the NSA Crane facility: a DEI-owned and operated 69 kilovolts ("kV") sub-transmission line that provides the primary utility service, and a [redacted]-owned (but DEI-operated) 69 kV line as the [redacted] utility service.[72] The Navy wanted to maintain electrical power at NSA Crane to operate critical loads during a major grid outage where both the primary and backup utility services were without power. To do this, the Navy is creating a microgrid to isolate and power its critical load.[73] A [redacted] will function as the [redacted] for the microgrid.[74]

DEI plans to install and operate the necessary electrical lines, equipment and communications to interconnect and interface the existing solar and proposed BESS with the NSA Crane microgrid.[75] Although the solar and battery may receive

[69] Cause No. 45253, Confidential OUCC Attachment AAA-4C – DEI's Confidential Response to OUCC DR Set 14.2-A, NSA Crane Microgrid Study.
[70] Ritch, Direct at 3, lines 15 – 17.
[71] Cause No. 45002, Final Order, May 30, 2018.
[72] DEI operates both primary and backup transmissions lines serving NSA Crane. DEI owns and operates the primary service but [redacted] owns the backup service that DEI also operates to serve NSA Crane. *See* NSA Crane Microgrid Study, p. 2.
[73] *See* NSA Crane Microgrid Study, pp. 7 – 8.
[74] *See* NSA Crane Microgrid Study, p. 6.
[75] Ritch, Direct at 8, lines 3 – 6.

"[redacted]" dispatch from NSA Crane, in reality, DEI's solar and battery will be secondary or supplemental power sources for the NSA Crane microgrid.[76]

Q: Would generation and storage assets be required to provide electric service to NSA Crane migrogrid in the event of a major grid outage?

A: Yes. DEI witness Andrew S. Ritch noted, "three generation and storage assets would be required to provide electrical service to NSA Crane microgrid in the event of a major grid outage: 1) the existing 17 MWac Crane Solar Facility owned by Duke Energy, 2) a new battery energy storage system ("BESS"), and 3) new diesel generators."[77]

Q: Why then would the [redacted] be the primary power source while DEI's solar and battery would be the secondary or supplemental sources for the microgrid?

A: The [redacted] are the [redacted] to meet its initial system support requirements of the microgrid. Otherwise, aside from being impractical to reconfigure the system, it will also require a [redacted] if BESS takes the initial system support role for the microgrid.[78]

Moreover, based on the NSA Crane Microgrid Study, [redacted], both solar and battery could only support the microgrid critical loads for [redacted] of outage duration.[79] Further, for a solar-and-battery-only configuration or combination to serve the microgrid critical loads in an [redacted], it will require an

[76] *See* NSA Crane Microgrid Study, p. 5.
[77] Ritch, Direct at 4, lines 7 – 10.
[78] *See* NSA Crane Microgrid Study, pp. 5 and 73.
[79] *See* NSA Crane Microgrid Study, pp. 5.

[redacted] to do so.[80] However, the [redacted] would have ample capacity to serve the microgrid total load—both critical and non-critical loads—for an extended period, and [redacted].[81] Therefore, during a major grid outage event with the microgrid in island mode, it is critical to have [redacted] with the solar and battery as secondary or supplemental support when called upon or dispatched.

Q: Will NSA Crane microgrid operate without solar and BESS?

A: Most definitely, yes. The NSA Crane microgrid design and configuration allows it to electrically isolate and island itself and its loads from its normal power sources including the existing solar and proposed battery during a major grid outage. Once isolated and islanded the [redacted] to power up the microgrid. The microgrid controller, topology and load shedding capability allow it to configure and reconfigure its systems and loads to optimize generation capacity and load requirements. On an island mode, it would then be necessary for DEI system operators to [redacted] with NSA Crane microgrid operators [redacted] with the microgrid. DEI needs to follow necessary switching sequences to [redacted] during the interconnection. The microgrid operators would be diligent in monitoring DEI's solar and battery switching sequences and protocols to [redacted]

[80] Cause No. 45253, OUCC Attachment AAA-5 – DEI Response to OUCC Set 14.24. *See also* NSA Crane Microgrid Study, Section 6.1.2 – Microgrid Generator Sizing, pp. 44 – 46.
[81] *See* NSA Crane Microgrid Study, p. 6.

[redacted] of any critical loads or [redacted]. These switching sequences and interconnection protocols may take DEI [redacted] to accomplish and bring the solar and battery online with the microgrid.[82] This only shows the position of the solar and battery in the [redacted] to the microgrid because the [redacted] is of no consequence or concern to the microgrid because by then, its [redacted] are already online and providing sufficient power to its loads.

Q: During normal grid operations, will BESS provide NSA Crane any support?

A: No. During normal grid operations, NSA Crane would take primary utility service from existing DEI lines. The battery will be charging to maintain a set state of charge level. DEI may charge, discharge or otherwise, play or simulate operational scenarios with it, but it would not provide any utility service to NSA Crane.

Q: Would the BESS provide any grid service to or dispatch by the Midcontinent Independent System Operator ("MISO")?

A: No. At present, MISO will not be able to "see" BESS in its network topology or dispatch it. Nor will BESS be able to participate at MISO markets and provide revenue-generating services at an economical scale sufficient to justify ratepayers paying for it.[83]

Q: Are there quantifiable operational benefits that ultimately flow to ratepayers from the proposed solar and battery interconnection projects?

A: As proposed, there are little or no quantifiable operational benefits. Until the Camp Atterbury Microgrid and Nabb Battery projects are operational, DEI gains no

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[82] *See* NSA Crane Microgrid Study, p. 3.
[83] *See* NSA Crane Microgrid Study, pp. 24 – 31.

operational data and insight. DEI's operational education can begin once these projects are functional, and that experience / data can be analyzed and hopefully applied to better understanding and deploying the technologies here in Indiana. However, until that process is complete, there is no need to spend an additional $10 million on additional battery research with the BESS. Given the exceptionally low probability of the BESS/solar configuration actually being called upon ([redacted] unable to provide power and simultaneously the Navy [redacted]), DEI will learn little from the project. It will not gain material insight into microgrid operations and offers no benefits to ratepayers from potential MISO participation.

Q: Mr. Ritch identified the benefits of the battery project including the "enhance reliability of service to customers and provide ancillary services, such as Regulating Reserves, to MISO."[84] Did your evaluation results show such benefits from the BESS project?

A: No. The BESS project only benefits NSA Crane and not DEI ratepayers. BESS does not enhance reliability of service to customers (and [redacted] it suffers the same fate as the battery storage in Arizona that exploded on April 19, 2019).[85]

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[84] Ritch, Direct at 6, lines 14 – 15.

[85] Website: https://www.azcentral.com/story/news/local/surprise/2019/09/30/phoenix-peoria-and-surprise-enact-battery-storage-laws/2305933001/. Accessed: 10/23/2019.

Figure 1: *The APS McMicken power station near Grand Avenue and Deer Valley Road was the site of an explosion April 26. [Jason Stone/Independent Newsmedia].*[86]

There are multiple energy market services and opportunities at MISO and other grid efficiency benefits for generation resources.[87] As Mr. Ritch indicated, becoming a market participant and offering regulating reserve services at MISO could be a viable option for DEI's BESS.[88] However, if this were the only revenue-generating benefit DEI could find for BESS, then it would be a bad deal for ratepayers. Even if BESS could offer and provide regulating reserves to MISO, DEI has not quantified or shown such benefits could economically justify the investment it asks of ratepayers. DEI has not shown that all revenues generated from BESS, if any, could pay for the O&M and capital maintenance expenditures it would incur. As provided in response to OUCC data requests, DEI is seeking regulatory pre-

[86] Website: https://yourvalley.net/yourvalley/business/aps-explosion-in-surprise-goes-viral-world-watching-investigation-of-battery-mishap/. Accessed: 09/23/2019.
[87] *See* NSA Crane Microgrid Study, Section 4.2, pp. 24 -31.
[88] Ritch, Direct at 7, lines 1 – 5.

approval for the solar and battery interconnection projects without first securing its own corporate management approval for these projects or for project funding, which must still compete with all other Duke capital projects for approval.[89]

Q: What are your concerns regarding DEI including $10 million in base rates for its proposed solar and battery interconnection projects?

A: My first concern is finding out, as discussed earlier, that DEI's proposed microgrid project is not actually a "real" or true microgrid project. Rather, DEI's proposed projects entail interconnecting the existing Crane Solar facility and the proposed BESS with the Navy's planned microgrid at NSA Crane. DEI would neither own, control, nor operate the NSA Crane planned microgrid. Second, neither DEI's existing solar, nor its proposed BESS, are primary or critical power sources for the planned NSA Crane microgrid. In an event of the a major grid outage, wherein [redacted] to NSA Crane [redacted] the microgrid operators at NSA Crane will require DEI system operators to [redacted] they will allow DEI to interconnect the solar and battery to the microgrid. The microgrid [redacted] from either DEI solar or battery to power up the microgrid. This leaves BESS with a limited operational functionality at best. Third, DEI's solar-and-battery-only combination [redacted] the microgrid critical loads for [redacted] at a level that would provide a sense of security to Crane. During island mode, the microgrid operators must have [redacted] whenever the solar and battery are connected with the

[89] Cause No. 45253, OUCC Attachment AAA-6 – DEI's Response to OUCC DR Set 14.6, 14.8 and 14.9.

microgrid. In other words, it is critical the microgrid operators do not leave DEI solar and battery on their own and online with the microgrid without [redacted]. Fourth, BESS would be a dedicated resource to NSA Crane during outages and would not provide any benefits to ratepayers during normal operations. Revenues generated from NSA Crane could not justify the cost of BESS. Should DEI qualify BESS to offer services to the MISO markets, the revenues generated could not compensate for the O&M and capital expenditures BESS would incur throughout its useful life. Finally, faced with no actual quantifiable operational benefits or prospective revenues to offset costs, the solar and BESS interconnection projects are bad deals for ratepayers who will shoulder the initial $10 million project costs and then every penny of O&M and capital expenditures once embedded in future rates.

Q: What is your recommendation regarding DEI's solar and BESS interconnection projects at NSA Crane?

A: I recommend a $10 million adjustment (including AFUDC) to remove the capital expenditures found in Mr. Ritch's Direct Testimony, p. 12, lines 1 – 2, including any and all O&M expenditures associated with and related to the DEI's solar and BESS interconnection projects, from the 2020 forecasted Test Year.

Q: What do you recommend?

A: Based on the results of my analysis, I recommend the Commission:

1. Require DEI to normalize the O&M expenditures of its generating facilities including the cyclical maintenance outages. Adopt a seven-year average methodology to normalize the O&M expenses and associated major outage costs. I recommend an adjustment of $80 million to reduce the forecasted Test Year O&M expenses of DEI's generating facilities to $149 million.

2. Require DEI to adopt a seven-year average methodology to normalize the Edwardsport IGCC overall O&M Expenditures, Major Outage Expenses, and Miscellaneous Administrative and General Benefits ("Misc. G&A") costs (forecasted and attributed to Edwardsport by other corporate groups) in 2020. I recommend an adjustment to decrease the Edwardsport IGCC O&M, Major Outage and Misc. A&G expenses to an overall total of $61.87 million in the forecasted Test Year 2020.

3. Require DEI to develop an operational plan to manage storm restoration and incorporate the developed operational plan within its vegetation management and TDSIC programs to ensure integration of the prescribed goals in these programs. I recommend the Commission set the initial amount of Major Storm Reserve at $6 million and adopt the attendant mechanism of recording over and under collection of revenues in the reserve account. Accordingly, I recommend a $6.7 million decrease to forecasted Test Year Major Storm Reserve.

4. Disallow and remove $10 million (including AFUDC) capital expenditures including any and all O&M expenditures associated with and related to the DEI's solar and BESS interconnection projects, from the forecasted Test Year.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

I. EDUCATIONAL BACKGROUND AND EXPERIENCE

Q: Please describe your educational background and experience.

A: I hold an MBA from the University of the Philippines ("UP"), in Diliman, Quezon City, Philippines. I also hold a Bachelor's Degree in Electrical Engineering from the University of Santo Tomas ("UST"), in Manila, Philippines.

I joined the OUCC in July 2009, and have completed the regulatory studies program at Michigan State University sponsored by the National Association of Regulatory Utility Commissioners ("NARUC"). I have also participated in other utility and renewable energy resources-related seminars, forums, and conferences.

Prior to joining the OUCC, I worked for the Manila Electric Company ("MERALCO") in the Philippines as a Senior Project Engineer responsible for overall project and account management for large and medium industrial and commercial customers. I evaluated electrical plans, designed overhead and underground primary and secondary distribution lines and facilities, primary and secondary line revamps, extensions and upgrades with voltages up to 34.5 kV. I successfully completed the MERALCO Power Engineering Program, a two-year program designed for engineers in the power and electrical utility industry.

Q: What did you do to prepare your testimony?

A: I reviewed the petition, direct testimony and attached exhibits filed by DEI in this Cause. I wrote discovery questions and reviewed DEI's corresponding responses. On Sept. 9, 2019, I attended the DEI field hearing held in Carmel, IN associated with this Cause. On Aug. 29, 2019, I attended and participated in a technical conference call with DEI witnesses to discuss topics and issues related to the Edwardsport IGCC cost estimates of the case.

Duke Energy Indiana, LLC Attachment IG 17.1-A

Fossil Hydro Operation Budget O&M for Generating Units 1/ 2/

$ in Thousands

	2018	2020
Cayuga Coal	51,095	49,511
Cayuga CT	3,745	812
DEI Reg Solar	236	288
Edwardsport IGCC Plant	105,091	145,798
Gallagher Common	11,002	9,220
Gibson Coal	128,839	144,056
Henry County CT	2,196	2,697
Madison CT	4,654	5,984
Markland Hydro	2,145	2,488
Noblesville CT	7,189	13,313
Vermillion CT	3,466	4,140
Wheatland CT	2,814	6,143
Regional Support & Other	(4,097)	(5,469)
	318,373	378,980

1/ Data not available at unit level.
2/ Does not include payroll taxes, property tax, property insurance or Edwardsport regulatory credit.

IG
IURC Cause No. 45253
Data Request Set No. 2
Received: July 15, 2019

IG 2.11

Request:

Please refer to Mr. Gurganus' Direct at page 11, lines 4-5 and at page 18, lines 4-12.

a. Please identify the actual number of contractors at the Edwardsport IGCC plant for each year from 2013 through 2018, as well as the projected number of contractors for 2019 and 2020.

b. Please identify the cost of labor (including salary, incentives, benefits, and payroll tax) associated with contractors at the Edwardsport IGCC plant for each year from 2013 through 2018, as well as the projected cost of labor for contractors for 2019 and 2020.

c. Please identify the actual number of employees at the Edwardsport IGCC plant for each year from 2013 through 2018, as well as the projected number of employees for 2019 and 2020.

d. Please identify the cost of labor (including salary, incentives, benefits, and payroll tax) associated with employees at the Edwardsport IGCC plant for each year from 2013 through 2018, as well as the projected cost of labor for employees for 2019 and 2020.

e. *For purposes of this question, "O&M expense" is defined in the same manner as the 2016 and 2018 Edwardsport settlement agreements. Specifically, "O&M expense" is defined to include operating and maintenance expenses, payroll taxes, property taxes, property insurance, and net of the credit for old Edwardsport operating expenses (but not fuel and depreciation).*

   Please identify the actual amount of O&M expense for each year from 2013 through 2018, as well as the projected O&M expense for 2019 and 2020.

Response:

a. Assuming this Request seeks information regarding contractors who work at the station on a long-term basis and not contractors brought in for a special project on a short-term basis, please see the table below for the average number of contractors by year.

e. Please see the table below for 2013-2018 actual costs and 2019-2020 projected costs for O&M as defined in the 2016 and 2018 IGCC Settlement Agreements.

	Cost (dollars in millions)							
	2013	2014	2015	2016	2017	2018	2019	2020
Station O&M	$35.9	$71.0	$96.4	$133.8	$109.2	$102.9	$102.3	$145.8
Less: 2020 major outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.4
Adjusted station O&M	35.9	71.0	96.4	133.8	109.2	102.9	102.3	99.4
Non-station department O&M [1]	0.3	0.6	0.8	0.9	2.9	2.7	2.5	2.6
TOTAL O&M	$36.2	$71.6	$97.2	$134.7	$112.1	$105.6	$104.8	$102.0
Payroll tax	0.7	1.3	1.5	2.0	1.9	1.9	2.2	2.5
Property insurance	5.7	3.3	1.3	0.2	0.3	0.3	0.3	0.3
Property tax	0.0	0.4	0.9	1.1	1.5	1.0	4.8	5.6
Credit for retired coal plant	(3.3)	(5.7)	(5.7)	(5.7)	(5.7)	(5.7)	(5.7)	(5.7)[2]
Total	$39.3	$70.9	$95.2	$132.3	$110.1	$103.1	$106.4	$105.1

Witness: Cecil Gurganus

[1] Represents O&M costs from non-station departments that support Edwardsport.

[2] Included in 2020 for comparison purposes.

OUCC Attachment AAA-3 is Confidential

OUCC
IURC Cause No. 45253
Data Request Set No. 14
Received: September 3, 2019

OUCC 14.2

Request:

Please provide a complete and unredacted copy of the Crane Microgrid Feasibility Study as referenced on page 3 of Mr. Ritch's testimony.

Response:

See Confidential Attachment OUCC 14.2-A.

Witness: Andrew S. Ritch

OUCC
IURC Cause No. 45253
Data Request Set No. 14
Received: September 3, 2019

OUCC 14.24

Request:

How long of an outage duration, in hours, can BESS support or serve the NSA Crane total critical load?

Response:

Per the NSA Crane Microgrid Design Study, the 17MW existing solar PV facility, new 5MWh BESS and new 2MW Diesel Generators would be able to back-up Tier 1+ Crane critical load for one (1) week.

Witness: Andrew S. Ritch

OUCC
IURC Cause No. 45253
Data Request Set No. 14
Received: September 3, 2019

OUCC 14.6

Request:

On page 5, line 1 of his testimony, Mr. Ritch states the 5MW BESS "will require applicable corporate and regulatory approval prior to construction." He goes on to state that DEI has decided to move forward with the 5 MW BESS. Has DEI secured applicable corporate and regulatory approval for the 5 MW BESS?

Response:

Duke Energy Indiana is currently seeking regulatory approval for this project as part of this current rate case proceeding. Duke Energy Indiana plans on requesting corporate funding approval for this project in the fourth quarter of 2019 as part of its development effort.

Witness: Andrew S. Ritch

OUCC
IURC Cause No. 45253
Data Request Set No. 14
Received: September 3, 2019

OUCC 14.8

Request:

Please explain DEI's internal formal approval process and procedure in relation to the proposed Crane Microgrid project. Please provide all internal documents used and presented to DEI management in support of the proposed Crane Microgrid project. If none, please explain why.

Response:

A funding request for the project will be submitted to the company representative (expected to be the VP of Distributed Energy Technology Business and Product Development) with the appropriate delegation of authority to approve the funds. No requests for funding approval have been submitted at this time.

Witness: Andrew S. Ritch

OUCC
IURC Cause No. 45253
Data Request Set No. 14
Received: September 3, 2019

OUCC 14.9

Request:

Please provide the documents showing DEI management's approval of the proposed Crane Microgrid project including any capital or funding authorization for the project. If there is no internal document showing DEI management's approval of the Crane Microgrid project, please explain why there is none.

Response:

No requests for funding approval have been submitted at this time. This is expected to occur in the fourth quarter of 2019.

Witness: Andrew S. Ritch

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Anthony A. Alvarez
Utility Analyst
Indiana Office of Utility Consumer Counselor
Cause No. 45253
Duke Energy Indiana, LLC

October 30, 2019
Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail this 30th day of October to the following:

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