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REGULATORY COMMISSION

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF DUKE ENREGY INDIANA, LLC'S GENERATION UNIT COMMITMENT DECISIONS	**)))**	**CAUSE NO. 38707 – FAC123 S1**

SUBMISSION OF REVISIONS TO CAC's PUBLIC TESTIMONY

Citizens Action Coalition ("CAC") hereby provides notice of revisions to the testimony of CAC Witness Burgess marked as CAC Exhibit 1, in the above-referenced Cause to the Indiana Utility Regulatory Commission ("Commission"). The revisions reflect changes to redactions in light of the information Duke has agreed to make public in Mr. Burgess's testimony.

The redlined pages and an entirely clean version of Mr. Burgess's revised public testimony is attached. The clean version of the revised public testimony with the original public attachments will be offered into the record at the evidentiary hearing as CAC Exhibit 1. CAC is filing the confidential version of revised testimony, under seal, pursuant to the Commission's September 15, 2020 docket entry.

Respectfully submitted,

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CERTIFICATE OF SERVICE

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CLEAN VERSION OF REVISED TESTIMONY

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF DUKE ENERGY INDIANA, LLC'S GENERATION UNIT COMMITMENT DECISIONS	**)) CAUSE NO. 38707 FAC 123 S1)**

DIRECT TESTIMONY OF EDWARD BURGESS

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA

JULY 31, 2020

PUBLIC VERSION

I. Summary of Findings and Recommendations

Q. Please summarize your key findings

A. My findings can be summarized as followed:

1. DEI frequently commits its coal generation units as Must Run even when they are forecasted by DEI to yield economic losses.
2. This practice is most common at the Edwardsport Integrated Gasification Combined Cycle plant which operated with a Must Run designation with coal as the primary fuel source during every week of the FAC 123 period, despite the fact that this approach was forecasted to have economic losses the majority of the time. This led to $4.9 million[1] in economic losses during the FAC 123 period that DEI has charged to its customers.
3. DEI's contract to serve one steam customer led to Must Run designations at the Cayuga plant that caused $1.4 million in higher costs to all electricity customers than they otherwise would have paid.
4. DEI routinely under-forecasts the economic losses that actually occur from plants that are given a Must Run commitment status, likely leading to a greater number of Must Run designations and higher costs to customers.
5. In its modeled forecasts to determine the amount of coal it will burn, DEI presumes Must Run status at several of its coal-burning plants, which can lead DEI to overestimate the amount of coal it will need. These forecasts in turn guide

[1] Based on $[redacted] in MISO revenues minus $[redacted] in production costs as identified in DEI's Response to CAC Data Request 4.14, Confidential Attachments CAC 4.14-A and 4.14-B (included as Attachments EB-14-Confidential and EB-15-Confidential).

coal contract negotiations.

6. While not applicable in the FAC 123 period, DEI's assumed pricing for coal fuel sometimes includes "decrement pricing" which could distort the unit commitment and dispatch of its coal plants at the expense of its customers. DEI's coal inventories steadily increased over the FAC 123 period, leading to greater likelihood of decrement pricing being used in upcoming FAC periods.

Q. Please summarize your recommendations.

A. My recommendations are as follows:

1. The Commission should reduce the amount that DEI can collect from its customers by the amount equal to the economic losses that occur due to operating Edwardsport with coal as the primary fuel source during times when DEI predicts losses to occur but commits the plant as Must Run anyways. Additionally, the Commission should further reduce the amount collected by any foregone economic benefits that DEI predicts from operating the plant on natural gas where DEI chooses to operate the plant on coal syngas instead. These reductions total $7.9 million for the FAC 123 period.

2. The Commission should require DEI to assign the economic losses associated with Must Run designations at Cayuga to DEI or the steam customer (rather than to electricity customers) if the Must Run status was forecasted to yield economic losses and therefore presumptively attributable to the steam customer.[2] These losses total $1.4 million for the FAC 123 period. These economic losses should be assigned to DEI or the steam customer in future FAC proceedings as well.

[2] Possible exceptions to this could include Must Run status for safety or testing needs.

3. The Commission should require DEI to provide additional reporting on its unit commitment decisions going forward as part of future FAC applications.

4. The Commission should require DEI to remove Must Run designations from the medium-term generation forecast models used in the FAC insofar as these designations increase the likelihood of coal oversupply.

5. The Commission should limit future cost recovery for coal fuel through the FAC if the inputs used for unit commitment purposes include decrement pricing. In the event decrement pricing occurs, the same decrement should be applied to fuel costs recovered through the FAC.

II. Introduction and Summary

Q. Please state your name and business address.

A. My name is Ed Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. Please describe your professional background and experience.

A. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master’s degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Arts degree in Chemistry from Princeton University.

Now, I am a leader on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric power sector on issues relating to resource planning, transmission planning, renewable energy, energy storage, utility rate design and program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues, including filing expert testimony before state regulatory commissions in California, Oregon, Massachusetts, and South Carolina. I have also aided in drafting testimony or formal comments for state regulatory commission proceedings in Arizona, Pennsylvania, New Hampshire, New York, North Carolina, Maryland, Illinois, New Mexico, and the Federal Energy Regulatory Commission. A full resume is attached in Attachment EB-1.

Q. Have you testified previously before the Indiana Utility Regulatory Commission ("Commission" or "IURC")?

A. No, however I have advised clients on IURC rules and procedures, specifically regarding the updates to the rules on resource planning that began in 2016.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Citizens Action Coalition of Indiana ("CAC").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) provide an overview of the FAC and how the costs it recovers are linked to DEI's unit commitment and dispatch decisions; 2) identify problems with the unit commitment and dispatch decisions happening within DEI's coal fleet that are increasing costs for DEI's customers; 3) provide plant-specific details on the problems identified; 4) identify general policy issues and concerns related to DEI's coal fleet; and 5) offer recommendations on how the Commission should remedy the issues identified throughout my testimony.

III. Overview of FAC

A. General FAC construct and impact on customer bills

Q. Have you reviewed Duke's application for fuel cost recovery under FAC 123 as well as Duke's direct testimony in this sub-docket investigation?

A. Yes.

Q. Please describe your understanding of the FAC construct.

A. The FAC is an adjustor mechanism charged to all of DEI's retail customers that recovers the portion of fuel costs not included in base rates. A new FAC is set every three months and reflects a few key components: 1) a forecast of future fuel costs expected to be incurred during the upcoming FAC period; 2) a reconciliation factor for the previous FAC period, which trues up any differences between forecasted and actual fuel costs; and; 3) a factor that subtracts the amount of fuel costs already recovered through base rates. For example, in the FAC 123 application, DEI anticipated that total fuel costs would be $179.5 million for the months of April 2020 through June 2020, which corresponds to a retail rate of about $0.025/kWh.[3] Additionally, during the September 2019 through November 2019 reconciliation period covered by FAC 123, DEI over-

[3] Cause No. 38707 FAC 123, DEI Verified Petition, Exh. A, Schedule 1.

collected fuel costs by about $12.9 million, which corresponds to a reconciliation factor of about -$0.002/kWh. Meanwhile, about $104.9 million of fuel costs are expected to be recovered during the April 2020 through June 2020 forecast period through the base fuel rate of ~$0.014/kWh. This leaves a remaining balance of about $62 million to be recovered through the FAC in the April to June 2020 timeframe, corresponding to a rate of about $0.008/kWh for the FAC 123 period.

Q. How would these factors (and customer bills) change if DEI's fuel costs were substantially reduced?

A. In the short term, DEI customer bills could be reduced first through the FAC reconciliation factor if actual fuel costs were less than predicted. If this reduction in fuel costs persisted over time, I would also expect DEI's ongoing forecasts of future fuel costs to reflect these lower costs, and the FAC would be reduced accordingly.

Q. What are the main components of the overall fuel costs that DEI recovers in part through the FAC adjustment factors?

A. The table below provides a breakdown of the estimated fuel costs included in the FAC 123 application for the April 2020 through June 2020 period.[4]

[4] Cause No. 38707 FAC 123, DEI Verified Petition, Exh. A, Schedule 1.

Table 1: Estimated fuel costs included in the FAC 123 application for April - June 2020

FAC Component	Fuel Cost
Steam Generation (Coal)	$79,109,000
Hydro and Solar Generation	$-
Gas Combustion Turbine	$26,134,000
Integrated Gasification Combined Cycle (Edwardsport)	$13,212,000
Purchased Power	$64,213,000
Net MISO Energy Market	$(2,300,000)
Steam Sales	$(869,000)
Total	$179,499,000

In total, fuel for DEI's coal plants (including fuel used to power both DEI's steam generation plants and the Edwardsport plant, which always ran with coal as the primary fuel source during the FAC 123 period) comprised $92 million or about 51% of the fuel costs that are at issue in the FAC 123 proceeding.

Q. Do these costs comprise the total costs to operate these plants?

A. No. The FAC only recovers fuel costs and excludes other operating costs such as operations and maintenance costs, and emissions allowances.

B. Role of dispatch decisions in FAC fuel costs

Q. Please explain how DEI's unit commitment and dispatch decisions affect the FAC fuel costs.

A. In his direct testimony, Mr. Swez contends that DEI's commitment practices serve to minimize customer costs by maximizing each unit's economic value both generally and during the three-month period covered by this FAC subdocket proceeding.[5] Least cost operations depend both on fuel as well as other variable costs, with the former being the most significant component. Minimizing the fuel costs that are charged to customers through the FAC depends upon DEI making unit commitment and dispatch decisions that can be reasonably predicted to be the lowest cost option for its customers. DEI contends that it attempts to minimize such fuel costs by using a variety of decision-making tools.

C. Decision-making tools used by DEI that influence coal fleet unit commitment and dispatch

Q. Can you provide an overview of the relevant decision-making tools and processes that influence DEI's unit commitment status, and how it recovers the cost of that dispatch through the FAC?

A. Yes. While, as discussed further below, Duke automatically commits some of its coal units as must run whenever those units are available, there are a variety of tools used at various points in the process that Duke claims ultimately influence the unit commitment

[5] Petitioner's Ex. 1 (Swez Direct Testimony), p. 29, lines 6-8.

and dispatch decisions of DEI's coal fleet and the related FAC costs charged to DEI customers. For some of these tools, Duke did not provide full access to the parties with confidentiality agreements in place. Thus, my precise understanding of the tools and how they operate is limited in some cases to the brief descriptions provided by Duke through discovery. Additionally, Duke allowed intervenors to view portions of these tools remotely during a 120-minute Microsoft Teams meeting. Generally, I would place the tools and decision-making processes into four categories:

- **Medium Term Analysis**: This includes GenTrader, a forward-looking forecasting tool used for estimating fuel burn over the coming months, which is the initial basis for the fuel cost rate in the FAC. The same model is also used to inform fuel purchasing decisions, which ultimately impact the costs collected through the FAC.
- **Short Term Analysis**: This includes various spreadsheet tools used by DEI to inform unit commitment decisions and MISO market offers over the coming days and weeks (e.g. Energy Cost Manual spreadsheet, Unit Cost Priority spreadsheet used to conduct daily Profit & Loss Analyses).
- **Hindsight Analysis**: This includes a tool used to assess past performance of DEI's generators (Profit &Loss Analyzer).
- **Post Analysis:** This includes a tool used to determine cost allocation of fuel costs (Sumatra).

I describe each of these four categories in more detail below.

1) <u>Medium Term Analysis (GenTrader)</u>

Q. Can you provide more details on the GenTrader tool used for Medium Term Analysis?

A. Yes. GenTrader provides a forecast of how DEI's generators are likely to operate over a predetermined time horizon, typically on the order of several months to several years. Within each GenTrader simulation, units are dispatched according to forecasted Midcontinent Independent System Operator ("MISO") market prices and generator costs informed by DEI's Energy Cost Manual (which I describe further in my testimony below). This gives DEI an estimate of the amount of fuel burn likely to occur over this period. DEI uses this tool for at least two relevant purposes:

a) Estimating future fuel costs for FAC applications: For example, within FAC 123, the forecasted fuel costs for the April-June 2020 period (which are used as the basis for the FAC 123 fuel adjustment factor rate prior to reconciliation) were estimated using GenTrader.[6]

b) Estimating fuel burn for coal supply agreement negotiations: Based on what was conveyed to me during the Microsoft Teams meeting described earlier, the coal burn estimated within GenTrader is used by DEI's fuels group to determine how much coal will be needed in the coming months or years, and to inform negotiations for new coal supply agreements.[7] These negotiated coal supply agreements and associated fuel prices

[6] I relied on relevant discovery to inform my understanding of this, including Duke's Responses and related Attachments to CAC Data Requests 4.28, 4.31, 4.32, 4.33, 8.4, and 8.10 (included as Attachments EB-2, EB-3-Confidential, and EB-31-Confidential).

[7] I relied on relevant discovery to inform my understanding of this, including Duke's Responses and related Attachments to CAC Data Requests 2.1-Confidential, 2.2, 4.26, 4.27, 4.29, 4.30, 5.7, 6.3, and 8.9 (included as Attachments EB-2, EB-3-Confidential, EB-23-Confidential, and EB-24-Confidential).

are then in turn used as a key input for DEI's analysis on unit commitment.

Q. Do you have any concerns about the input assumptions used by DEI in GenTrader?

A. Yes. While I was not able to review the model in full as described above, it is my understanding that Duke assumes that several of its coal units operate as "Must Run" units, regardless of MISO power prices. This includes Cayuga 1, Edwardsport, and Gibson units 1, 2 and 5.[8] Thus, even though DEI uses a least cost model to estimate the unit operations with the claimed objective of minimizing costs for ratepayers, it then essentially overrides this cost minimization objective by assuming that a certain subset of its coal units will be operating above a minimum level on a consistent daily basis for the next several years, regardless of what may be economically optimal at the time. What is even more concerning about this is that DEI uses this information for coal contract negotiations, which could ultimately lead to it procuring more coal than is economically sensible.

Q. Do you think it is appropriate to presume a certain amount of coal will be burned in the future by including must-run constraints in advance of actual contracting decisions?

A. No. This could lead and likely does lead to over-procurement of coal, or procurement under terms that ultimately harm customers. This practice by DEI is especially concerning for the Gibson plant for which DEI does not even claim to have the same operating constraints as it does for the Cayuga and Edwardsport units.

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[8] Duke Responses and related Attachments to CAC Data Requests 8.4 and 9.6 (included as Attachments EB-2 and EB-31-Confidential).

2) <u>Short-Term Analysis (Daily P&L Forecasts via Unit Cost Priority spreadsheet and Energy Cost Manual spreadsheet)</u>

Q. Can you provide more details on the spreadsheet tools DEI uses for its Short-Term Analysis?

A. Yes. There are two main tools that I am aware of: (1) the Energy Cost Manual (of which I was only provided limited virtual access via a Microsoft Teams meeting and a summary of inputs and equations, included as Attachment EB-16-Confidential); and, (2) the Unit Cost Priority spreadsheet (included as Attachment EB-18-Confidential).

Q. Please describe the first Short-Term Analysis tool, the Energy Cost Manual.

A. The Energy Cost Manual in essence serves as a comprehensive database of information about the operating characteristics and related costs of DEI's generation units. This includes details such as fuel costs, plant heat rates, emission-related costs, operations and maintenance costs, and so on. The Energy Cost Manual is also updated on a regular basis. Notably, a key input to the Energy Cost Manual consists of manual entries provided by DEI's fuels group regarding fuel prices. These prices reflect current coal supply agreements and any adjustment made to these prices for unit commitment purposes (e.g. coal decrement pricing).

Q. Do these fuel price inputs in the Energy Cost Manual reflect any "coal decrement pricing"?

A. It is my understanding that the coal fuel prices applicable in the FAC 123 period did not include any coal decrement pricing. However, going forward, future FAC periods will include decrement pricing, according to the testimony of Brett Phipps, as well as DEI's acknowledgement that FAC 125 will likely reflect coal decrement pricing.[9] I believe that the coal fuel price inputs to the Energy Cost Manual would be the primary place where coal decrement pricing would be reflected in DEI's forecast, and in turn influence subsequent DEI decisions, including plant unit commitment. Unfortunately, I'm unable to confirm where decrement pricing first comes into play since DEI did not provide CAC with the full Energy Cost Manual spreadsheet file.

Q. Please define "coal decrement pricing" and explain why it is relevant to this investigation, even if not applied during the FAC 123 reconciliation period.

A. The coal price decrement calculation reflects a decrease in the cost for each ton of coal used in deriving the dispatch cost at each generation unit. This is also included in the input assumptions DEI uses for its unit commitment decisions through the Daily Profit and Loss Analysis[10] as well as DEI's price offers submitted into the MISO marketplace. As DEI stated, "Coal considerations could impact the commitment of a unit through the coal price decrement calculation."[11]

Q. Why does DEI claim a decrement price is needed?

A. Duke contends that a coal price decrement equates to the avoided cost associated with preventing the necessity of storing excess coal, buying out of the contract, reselling the

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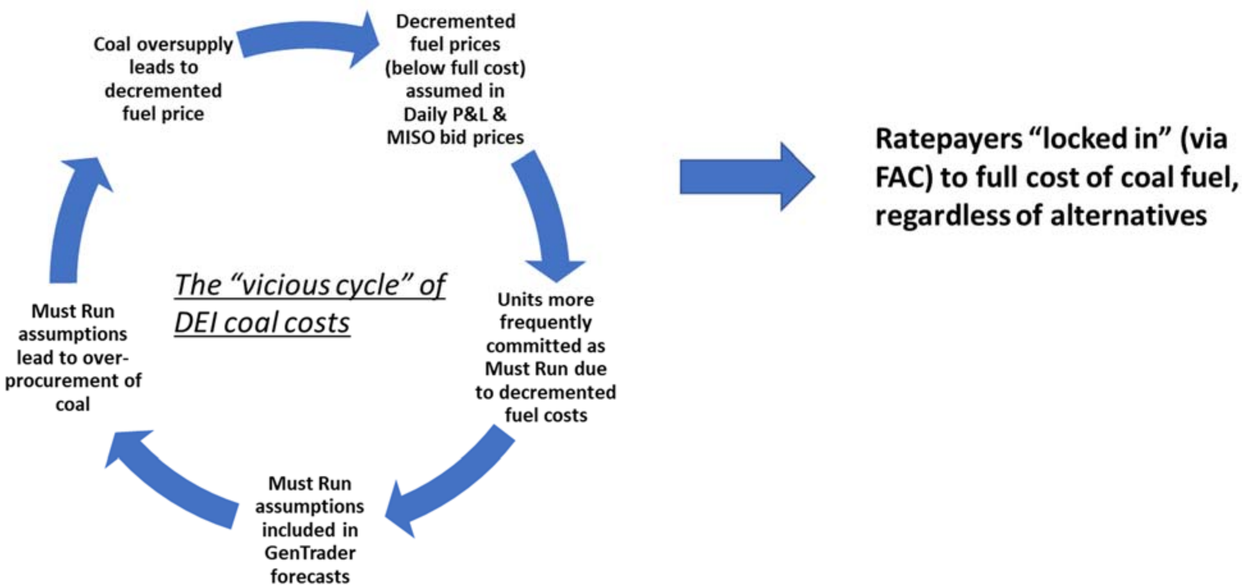
[9] Cause No. 38707 FAC 123, Petitioner's Ex. 4 (Phipps Direct), pp. 8-9.
Cause No. 38707 FAC 124, Petitioner's Ex. 6 (Swez Direct), p. 19 ("Although outside of this FAC reporting period, in early March, the Company started applying a coal price decrement to the dispatch costs of Gibson 1-5, Cayuga 1-2 and Edwardsport generating units to correctly reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. I will provide further updates in FAC 125, including a confidential exhibit that will provide the coal stack for every non-zero decrement update during the reconciliation period.")

[10] Duke Response and related Confidential Attachment to CAC Data Request 4.22 (included as Attachments EB-2 and EB-17-Confidential).

[11] Duke Response to CAC Data Request 4.13(b) (included as Attachment EB-2).

coal, or taking some other action to deal with DEI's anticipated excess coal inventories. This means that when DEI has especially high excess coal inventory levels, it artificially decreases the marginal price of coal in its analysis, making the coal units appear more economic for unit commitment decisions than they truly are from a retail customer standpoint. Thus, coal units are dispatched as lower cost units, while in reality, ratepayers cover the full cost through FAC, and lower cost resources are excluded. This practice is essentially a short-term fix for DEI's errors in long-term decision-making that have led to ongoing and significant coal oversupply challenges for Duke. However, by continuing to pass on the full fuel costs to customers there is no incentive for DEI to improve its coal procurement practices over the long term, thereby resulting in continually higher costs for DEI customers. This dynamic is illustrated in the figure below.



Stated differently, in the long term, DEI over-forecasts its coal consumption beyond what is economic, while in the short term it can apply a decrement to artificially lower the cost of coal dispatch to ensure that supply is consumed. This results in higher ratepayer costs and constitutes a policy concern that deserves attention to avoid this outcome in future FAC proceedings.

Q. Are there coal contracts currently in effect that could contribute to this dynamic in future FAC periods?

A. Yes. DEI currently has contracts in place that extend out as far as 2025.[12]

Q. Did DEI provide the Energy Cost Manual spreadsheet to you?

A. No. However, DEI showed portions of it through the Microsoft Teams meeting described earlier. DEI Supplemental Responses and Attachments to CAC Data Request 4.2 and 4.21(a) also provide some of the data assumed in the Energy Cost Manual and an explanation and equation of how DEI determines the price for the offers submitted into the MISO marketplace. In particular, DEI provides Confidential Attachment 4.21-A but notes "[t]his summary ties, close, but not exact, [*sic*] to the information in the Energy Cost Manual." These documents are included as part of my testimony as Attachment EB-2 (DEI Supplemental Responses to CAC Data Requests 4.2 and 4.21) and Attachment EB-16-Confidential (Confidential Attachment 4.21-A).

Q. What is the other primary tool used by DEI for its Short-Term Analysis?

A. The second tool used is the Unit Cost Priority spreadsheet ("UCP"). This tool contains the relevant information from the Energy Cost Manual spreadsheet necessary to perform the calculations to produce DEI's Daily Profit and Loss Analysis forecast. Consequently, this tool is central to the unit commitment and operating decisions at the core of this

[12] Cause No. 45253, Hearing Tr. F-94, lines 16-19; Duke Response to CAC 5.7 and Confidential Attachment 5.7-A (included as Attachments EB-3, EB-23-Confidential).

investigation. This spreadsheet was provided to CAC through discovery as Confidential Attachment 5.2-A (Attachment EB-2 for the response, Attachment EB-18-Confidential for the confidential attachment).

Q. Please briefly describe UCP and explain its role.

A. The UCP spreadsheet is DEI's primary tool for conducting its Daily Profit and Loss ("P&L") Analysis. The results of this analysis inform decisions regarding each unit's commitment status to the MISO marketplace. First, DEI estimates a unit's optimal dispatch level by comparing its incremental cost against the Locational Marginal Price ("LMP") at that unit's nodal point. Once the unit's output level is determined, the average cost of the unit is calculated at that output level. The unit's expected profit or loss is calculated as the difference between its expected revenue and its cost.

Q. How is the expected Daily P&L calculation supposed to inform DEI's MISO commitment status decisions?

A. According to the direct testimony of Mr. Swez, the Company strives to make unit commitment decisions that minimize the total cost of serving its customers by "maximiz[ing] the value of each generation unit" and the Daily P&L calculations are intended to aid in this process.[13] Specifically, DEI claims to designate each unit's commitment status as follows:

- If the Daily P&L forecast shows a positive margin (unit is "in the money"): the unit is offered as Must Run.
- If the Daily P&L forecast shows a margin close to zero (unit is "at the money" or

[13] Cause No. 38707 FAC 123-S1, Petitioner's Ex. 1 (Swez Direct Testimony), p. 18, line 18.

marginal): the unit is offered either as Economic or Must Run depending on other circumstances.

- If the Daily P&L forecast shows a negative margin (unit is “out of the money”): the unit is offered Economic.[14]

However, as I will explain in my testimony, the Company frequently makes unit commitment decisions that are at odds with those that the Daily P&L analysis would suggest. In short, DEI makes a large share of unit commitment decisions both outside of the MISO market optimization process and without regard for DEI’s own forecast of the value in the MISO market. This approach constrains the value of DEI’s market participation for its customers.

Q. How would the MISO market optimization provide additional value compared to Duke’s own forecast?

A. First, MISO optimizes the generation fleet across its entire footprint, not just for DEI’s generation fleet. Second, in contrast to DEI’s spreadsheet model, MISO uses more advanced mixed-integer linear programming techniques to optimally solve for the least cost set of generation resources while respecting reliability constraints (also known as Security Constrained Unit Commitment). Finally, the optimization conducted by MISO is the basis for energy market price formation and there does not rely on price forecasts (such as those used by DEI) that may be inaccurate.

[14] *See generally id*. pp. 7-10.

3) <u>Hindsight Analysis (Profit & Loss Analyzer)</u>

Q. Please describe the tool for DEI's hindsight analysis, the Profit & Loss Analyzer.

A. The Profit & Loss ("P&L") Analyzer is a third-party application that DEI uses to regularly review the Real Time operating results of generating units and their exposure to risks such as the Real Time market costs that result from a unit outage.[15] This tool is used to perform a hindsight analysis on actual generator performance and market revenues. In this sense, it does not impact the operation costs analyzed, but is used to inform future decisions.

Q. Did DEI provide the P&L Analyzer for your review?

A. No. Initially, Duke objected to CAC's discovery request because it would not be possible to provide results without providing the entire application, which is proprietary.[16] However, I was able to review one instance of such analysis during the Microsoft Teams call with DEI. During that same call, I was informed that although Duke will not provide the application, the output data would be relatively easy to save as a separate file and transfer. In CAC's Second Motion to Compel, CAC asked Duke to produce output, input, and formula files from the Profit & Loss Analyzer in a format that would not require the use of proprietary software to review. In its response to the Second Motion to Compel, Duke newly claimed that producing the output, input, and formula files would be "unduly burdensome" because the requested information "consists of fifty-six thousand, one-

[15] Duke Response and related Confidential Attachments to CAC Data Request 4.8 (included as Attachments EB-2, EB-10-Confidential, EB-11-Confidential, EB-12-Confidential, EB-13-Confidential).

[16] Duke Response and related Confidential Attachments to CAC Data Request 4.8 (included as Attachments EB-2, EB-10-Confidential, EB-11-Confidential, EB-12-Confidential, EB-13-Confidential).

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hundred and sixty separate files, each of which must be redacted to remove confidential information from other Duke Energy jurisdictions. Each day's file for each unit has 16 different views, therefore to produce 16 different daily views for the approximately 90 days in the FAC time for 39 generating units equates to fifty-six thousand, one-hundred and sixty separate files." Even after narrowing down the request to just the Edwardsport and Cayuga plants and to one of the 16 different views (DART P&L tab), Duke still refused to provide the files. CAC again narrowed its request given the quickly approaching testimony deadline to the DART P&L tab data for just Edwardsport for 9/5-9/8/2019 and 9/18-9/21/2019 which was provided to CAC three days before testimony was due.[17]

Q. Why is the P&L Analyzer relevant in this investigation if it is only used for a hindsight analysis?

A. My intention in requesting the P&L Analyzer results was to review the pattern of outages and subsequent impacts on FAC costs due to the operation of DEI's coal units. An unplanned outage can have significant cost implications for customers, as showcased by the Cayuga outage on Nov 13, 2019, described in Mr. Swez's testimony at pp. 24-25. However, if those outages happen on a regular basis and DEI is aware of such financial risks through its P&L Analyzer hindsight analysis results, then these risks could have been anticipated and should be factored in to DEI's unit commitment decision-making process. This could be done by simply including an outage risk premium in DEI's Daily

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[17] Due to the late and limited production of this information, CAC respectfully reserves the right to supplement or correct its testimony to the extent necessary.

P&L Analysis when making unit commitment decisions. Continuing to operate its units without accounting for this added financial risk will only lead to higher costs for ratepayers, which could potentially be avoided. The limited evidence Duke provided for the FAC 123 period points towards frequent unplanned outages at DEI's coal plants that worsen the economics of these units. I suspect that this pattern would apply to other FAC periods (and would extend into future FAC periods); however, I cannot confirm this without additional data that Duke has been unwilling to provide.

4) <u>Post Analysis (Sumatra for Cost Allocation)</u>

Q. Please describe the Sumatra model and its role in the FAC filing.

A. In preparation of the FAC filing, DEI also needs to determine the fuel cost allocated to serving its native load and the cost allocated to non-native load. The cost allocated to native load is recovered from DEI ratepayers through the FAC filing and the base rates. This calculation is performed with the use of a production cost model called Sumatra and in DEI's testimony it is referred as the post-analysis. The Sumatra model assigns most of the fuel costs recovered through the FAC to native load rather than non-native load.

Q. Have you determined the MWh share of each of DEI's generators that is serving native and non-native load?

A. Yes. About 99% of the MWh output from DEI's generators operating during the FAC 123 were allocated to native load.[18] A table below shows the breakdown for each plant.

[18] DEI Response and related Confidential Attachment to CAC Data Request 7.1 (included as Attachments EB-2 and EB-26-Confidential).

Table 2: Native and non-native load allocation by unit

Row Labels	Native	Non-Native
CIN.CAYUGA.1	[redacted]	[redacted]
CIN.CAYUGA.2	[redacted]	[redacted]
CIN.EDWPORT IGCC	[redacted]	[redacted]
CIN.GIBSON.1	[redacted]	[redacted]
CIN.GIBSON.2	[redacted]	[redacted]
CIN.GIBSON.3	[redacted]	[redacted]
CIN.GIBSON.4	[redacted]	[redacted]
CIN.GIBSON.5	[redacted]	[redacted]
Grand Total	**98.99%**	**1.01%**

Q. Can you summarize the process for how all of these decision-making tools are used and how they are linked to the FAC?

A. Yes. The diagram below provides an overview of the tools and their linkages based on my understanding from conversations with DEI and evidence provided in this docket.

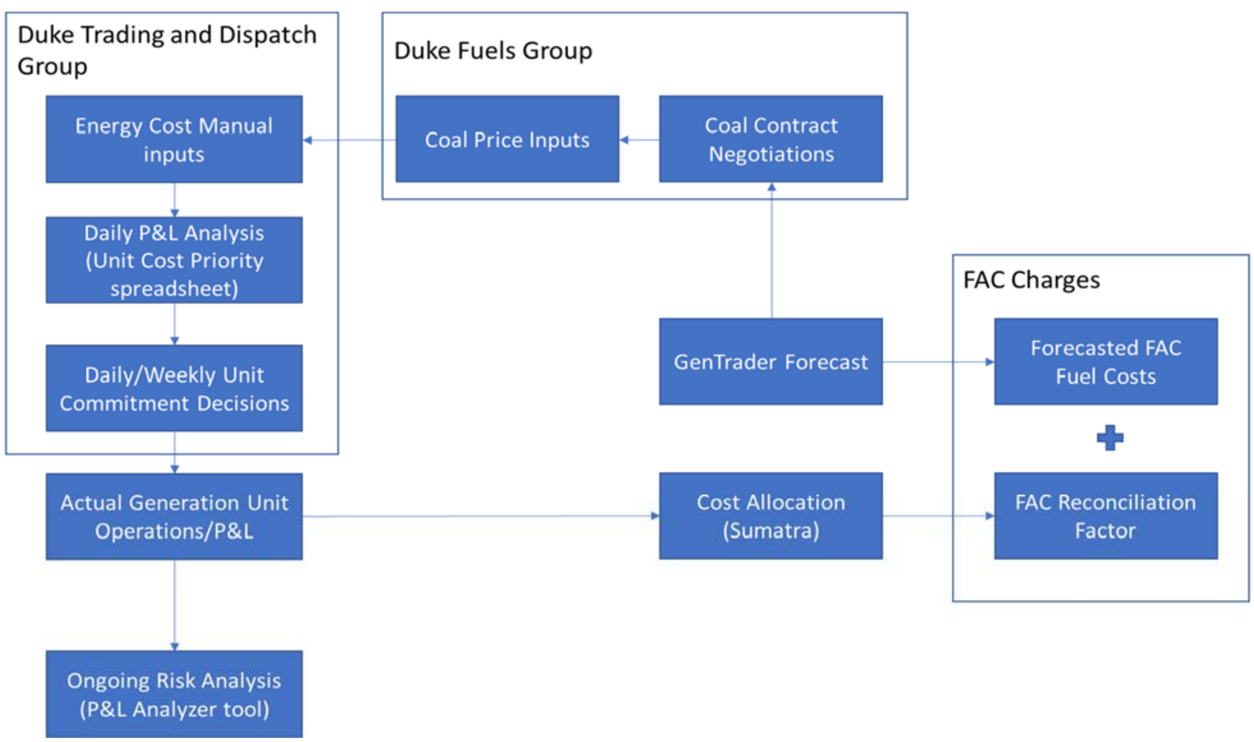

Figure 1. Overview of processes and tools used by DEI to determine unit commitment and dispatch, and their linkages to the FAC.

IV. General concerns with plant dispatch

A. DEI frequently commits its coal generation units as Must Run even when they are forecasted by DEI to yield economic losses.

Q. Have you reviewed DEI's Daily P&L forecasts, which, according to DEI's witness, informed unit commitment and dispatch decisions, during FAC 123 period?

A. Yes. After substantial delay, DEI provided on July 2, 2020, its Daily P&L forecasts in response to CAC's First Motion to Compel; however, upon review, CAC informed DEI that while each Daily P&L Analysis includes a forecast for the next three weeks, Duke had produced only the first week forecast from each analysis. DEI provided revised attachments that included all three weeks of each forecast on July 14, 2020.[19] These Daily P&L forecasts were performed in advance of unit commitment and dispatch decisions during the FAC 123 period (September 2019 through November 2019).[20] While DEI only provided the Daily P&L data sheets in PDF format, I transcribed the relevant data into Microsoft Excel format so that I could conduct a more detailed analysis.[21] The Daily P&L forecast is conducted by DEI to examine the economics of operating each unit on a weekly basis. Additionally, the forecasts include a 2-week and 3-week ahead outlook. The Daily P&L data sheets included information for eleven DEI generating units within

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[19] Duke Response to CAC Data Request 1.2, Revised Confidential Attachments 1.2-A, -B, and –C (included as Attachments EB-2 and EB-5-Confidential).
[20] Duke Response to CAC Data Request 1.2, Revised Confidential Attachments 1.2-A, -B, and –C (included as Attachments EB-2 and EB-5-Confidential).
[21] See my workpapers for the Excel version. Due to the fact that Daily P&L data sheets did not exist for every day in the FAC period, and since DEI generally applies a weekly outlook for its unit commitment decisions, and to avoid double counting from overlapping weeks, a subset of the Daily P&L data sheets were analyzed that covered the entire FAC period.

MISO (Cayuga 1 &2, Edwardsport, Gallagher 2 & 4, Gibson 1-5, Noblesville CC). Unit commitment decisions for each of these units for the week ahead are also notated in the data sheets.

Q. What were your findings based on this review of the Daily P&L data sheets?

A. Out of 115 total times when one of DEI's units was made available for the upcoming week (i.e. offered with a commitment status of either Economic or Must Run), I found that there were 68 instances where a unit was designated as Must Run. Of these 68 instances, 32 instances (>47%) coincided with a Daily P&L forecast for the week ahead that had a negative value (i.e. DEI expected the unit would be operating at an economic loss). DEI forecasted the total economic losses from these 32 instances to be $5.4 million.

Q. DEI claims that, in some cases, it is better to keep a plant online and incur temporary economic losses since those losses could be overcome by economic gains in subsequent days or weeks. Did you find this to be the case for the 32 instances you identified above that had a negative value?

A. For 7 of the 32 instances, the sum of the two-week ahead forecasted Daily P&L was indeed positive, despite a negative one-week ahead forecast. However, this still leaves 25 instances where even the two-week forecast showed economic losses. Moreover, these 25 instances still account for $5.1 million in week-ahead forecasted economic losses.

Q. Which plants were the largest contributors to these forecasted economic losses?

A. Edwardsport was by far the largest contributor, comprising $[redacted] million (or [redacted]%) of the $5.4 million in week-ahead forecasted economic losses. The confidential table below provides a summary of the forecasted economic gains and losses for each plant.

***Confidential* Table 3: FAC 123 Expected Profits/Losses Based on DEI Daily P&L Analysis**[22]

	Must Run Weeks w/ Economic Benefits (Week Ahead)		***Must Run Weeks w/ Economic Losses (Week Ahead)***		
Generating Unit	**# Weeks**	**Total**	**# Weeks**	**Total**	**% of Total $ of Forecasted Economic Losses**
CAYU_UN01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CAYU_UN02	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EDWA_CC01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GIBS_UN01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GIBS_UN02	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GIBS_UN03	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GIBS_UN05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NOBL_CC01	[redacted]	[redacted]			[redacted]
Grand Total	**36**	**$9,574,802**	**32**	**-$5,413,986**	100%

1) <u>Cycling Costs</u>

Q. What are the cycling costs that DEI purports to factor into its analysis for determining unit commitment?

A. DEI includes both startup costs, as well as shutdown costs. It should be noted that the terms the "shutdown costs" and "wear and tear" are used interchangeably by DEI.[23] Additionally, the estimated values of these shutdown costs were based upon a 1998 EPRI paper.[24]

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[22]Duke Response to CAC Data Request 1.2, Revised Confidential Attachments 1.2-A, -B, and –C (included as Attachments EB-2 and EB-5-Confidential).
[23] DEI Response and Confidential Attachment to CAC Data Request 2.4 (included as Attachments EB-2 and EB-7-Confidential).
[24] *Id.*

Q. Do you think that some of these 38 instances where units were Must Run despite a negative P&L value might have been justified on the basis of avoiding shutdown costs?

A. Possibly, but not in all cases. In many (but not all) of the instances involving the Gibson units, the weekly forecasted losses appear to be less than DEI's estimated shutdown costs.[25] Thus, if the unit was already online, it might make economic sense to continue operating it. However, this was not true for most of the instances involving the Cayuga units, or for all of the instances involving Edwardsport for which DEI has not identified any shutdown costs. As one example, during the week starting [redacted], Cayuga Unit 1 was forecasted to have $[redacted] in economic losses, which is far greater than the estimated shutdown cost of $[redacted] (and even greater than the combined shutdown and startup costs assumed for a full cycling which I estimate to be $[redacted]), and yet Cayuga Unit 1 was committed as Must Run. In these cases, it would have made more economic sense for DEI to offer these units with a designation of Economic rather than Must Run.

Q. Could DEI theoretically adjust its bid price to account for shutdown costs, thereby allowing it to offer its units with a designation of Economic instead of Must Run?

A. Yes. DEI could reduce its bid price to account for the fact that, to avoid the shutdown costs, it would be willing to accept a lower price for a unit, though to my knowledge this is not currently being done. Committing them as Must Run without properly accounting for the magnitude of any avoidable or non-avoidable costs is not appropriate in my

[25] Shutdown costs were provided by DEI in DEI Response to CAC Data Request 2.4 and are also included in the Daily P&L data sheets provided in DEI Response to CAC Data Request 1.2 (Attachments EB-2, EB-5-Confidential, and EB-7-Confidential).

opinion. As explained earlier, this sacrifices the added value of full participation in the MISO market optimization process and is therefore not in the best interest of customers.

Q. For the instances related to the Gibson units, would it still make sense to designate these as Must Run if the actual shutdown costs were significantly lower than what DEI has estimated?

A. Not necessarily. However, it would depend upon the precise amount of the estimated shutdown costs and amount of losses predicted.

Q. Is there reason to believe that the shutdown costs could be different than what DEI has estimated?

A. Yes. As mentioned Duke bases its estimate on a 1998 EPRI study, which may be somewhat outdated. More recent analyses have been conducted on this issue that could provide a more up to date view on shutdown costs. For example, the National Renewable Energy Laboratory ("NREL") study on steam turbine cycling costs as recently as 2012.[26]

Q. Generally speaking, should startup costs be a major reason why a generating unit should be offered to the MISO market as Must Run rather than Economic?

A. No. MISO market participants who offer their units as Economic into the Day Ahead market are eligible for MISO Day-Ahead Make Whole Payments.[27] This means that if a unit does not fully recover its startup costs through energy market revenue, it will be made whole. Meanwhile, as DEI has affirmed, units designated as Must Run are not

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[26] See https://www.nrel.gov/docs/fy12osti/55433.pdf
[27] See MISO Business Practice Manual 005 – Market Settlements, https://cdn.misoenergy.org/BPM%20005%20-%20Market%20Settlements49550.zip

granted any Make Whole Payments if startup costs are not fully recovered.[28] This suggests that it is actually in the best interest of DEI's customers for the Company to offer its units as Economic since there is less risk that startup costs will go unrecovered as there is if the unit is committed in MISO as Must Run.

2) <u>Edwardsport</u>

Q. How do these forecasted Daily P&L losses at Edwardsport correspond to the results of actual plant operations during the FAC 123 period?

A. During the FAC 123 period, Edwardsport was operated nearly continuously (98% of total hours), except for brief outages on 9/7/19 and 9/20/19. This is true despite DEI's own Daily P&L forecast showing economic losses occurring during [redacted], or [redacted]% of the time if operated with coal as a fuel source. The Daily P&L forecasts suggested that the net revenue from operating Edwardsport continuously on coal would amount $[redacted] million in economic losses.[29]

Q. Doesn't Edwardsport more frequently operate not just on coal, but by using a combination of coal-derived syngas and natural gas?

A. Yes. For example, based on data DEI reported to the EIA for the Sept-Nov 2019 period, I found that the MWh output of Edwardsport was fueled 74% by coal-derived syngas and 26% by natural gas.[30]

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[28] DEI Responses to CAC Data Requests 2.5 and 2.6 (included as Attachment EB-2).
[29] DEI Response to CAC Data Request 4.14 (included as Attachment EB-2) and Confidential Attachment 4.14-A and -B (included as Attachments EB-14-Confidential and EB-15-Confidential).
[30] See my workpaper.

Q. Does the economics of Edwardsport change if a similar share of natural gas is assumed as the fuel sources?

A. Assuming a 26% share of output to be powered by natural gas does improve the economics of Edwardsport. However, even under this scenario I still found that DEI's Daily P&L forecast had predicted economic losses for [redacted] weeks during the FAC 123 period and the total forecasted net revenues would be -$[redacted] million. Moreover, many of these "out of the money" weeks occurred consecutively, which suggests that DEI's commitment decision was not based upon anticipated economic gains over a longer time horizon.

Q. What were the actual net revenues for Edwardsport over the FAC 123 period?

A. In total, I found that the actual economic losses occurring from Edwardsport over the FAC 123 period were about $4.9 million, which is even greater than the losses DEI predicted in its Daily P&L forecasts as described above.

Q. What rationale did DEI use to schedule Edwardsport as a Must Run unit in the MISO Day-Ahead Market despite these economic losses?

A. Duke provided contradictory information in its Daily P&L analysis as compared to its reasoning for operating Edwardsport as a Must Run unit.[31] According to DEI's Response to CAC Data Request 6.4, the reason given for operating Edwardsport as Must Run in

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[31] Compare Duke Responses and Confidential Attachments to CAC Data Request 2.1 to Duke Response to CAC Data Request 6.4 (included as Attachment EB-2, Attachment EB-3-Confidential, Attachment EB-25-Confidential). Notably, CAC attempted to clarify this with CAC Data Request 4.13(a), but Duke objected to providing this information (included as Attachment EB-2).

every instance was: "[redacted]." [32] In other words, Duke's stated rationale for committing Edwardsport as Must Run in every instance during FAC 123 was that it was [redacted]. However, DEI's own Daily P&L analysis shows that Edwardsport was uneconomic to operate with coal as the primary fuel source [redacted] of the time during FAC 123. This directly contradicts DEI's stated reasoning, and is inconsistent with DEI's stated objective to "minimize total customer cost." [33]

Q. How did DEI respond when CAC questioned DEI's claim that Edwardsport was "[redacted]" despite conflicting Daily P&L Analysis?

A. DEI said, "[redacted]" and asserted that its decision was [redacted] over a longer time horizon.[34]

Q. Does this reasoning make sense to you?

A. No. Examining DEI's 2-week ahead, and 3-week ahead P&L forecasts for Edwardsport on the date in question clearly shows continued economic [redacted] were forecasted over a longer time horizon.

Q. Did DEI provide other reasons for operating units like Edwardsport as Must Run despite economic losses?

A. Yes. However, I do not find any of these reasons to be compelling. I address each of

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[32] DEI Response and Confidential Attachment to CAC Data Request 6.4 (included as Attachment EB-2 and Attachment EB-25-Confidential).
[33] DEI Response to CAC Data Request 2.11 (included as Attachment EB-2).
[34] DEI Confidential Response to CAC Data Request 9.3 (included as Attachment EB-3-Confidential).

these issues in my testimony below (see Section V-A). Based on my review of all information in this case, DEI's main criterion for selecting a Must Run designation is that it simply does so any time the gasifiers are available,[35] regardless of what may be in the best interest of its customers.

Q. Did DEI provide any additional information about its decision-making process for determining the unit commitment status of its plants?

A. Yes. DEI stated that it holds daily meetings each morning to determine the unit commitment status of its plants.[36] In addition to these meetings, DEI occasionally provides email communications to plant operators about these decisions.

Q. Did DEI respond to CAC's request to provide these email communications?

A. DEI initially objected to CAC's request for these communications. However, the Company did later provide a handful of relevant emails in discovery responses to Sierra Club, and provided a supplemental response to CAC's data request several weeks later which I have since reviewed.[37] While two of the emails refer to returning Edwardsport to service after an outage (Confidential Attachments CAC 2.12-C and 2.12-D included in Attachment EB-8-Confidential), none of the emails provided pertain to the unit commitment decision-making process for the plant. DEI later confirmed that there were no other similar emails pertaining to Edwardsport during the FAC 123 period.[38] Thus,

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[35] *See* Petitioner's Ex. 1 (Swez Direct Testimony) p. 25, lines 15-17 (" As Duke Energy Indiana has explained in every recent FAC proceeding, when the unit's gasifiers are available or operating, Edwardsport is being offered with a commitment status of Must-Run. . . . ").
[36] Petitioner's Ex. 1 (Swez Direct Testimony), p. 18, line 21 to p. 19, line 9.
[37] Duke Response and Attachments to CAC Data Request 2.12 (included as Attachment EB-2 and Attachment EB-8-Confidential); Duke Response and Attachments to Sierra Club Data Request 2.1 (included as Attachment EB-2 and Attachment EB-34-Confidential).
[38] DEI Response to CAC Data Request 9.5 (included as Attachment EB-2).

DEI does not appear to have any economically-based decision-making process for determining unit commitment status at Edwardsport.

B. DEI's Daily P&L forecasts used for unit commitment are overly optimistic and routinely under-forecast the economic losses occurring at units designated as Must Run.

1) <u>Analysis of actual daily profits/losses</u>

Q. Generally speaking, how accurate was DEI's forecasted Daily P&L relative to each plant's actual net operating revenues in the FAC 123 period?

A. CAC Data Request 4.14 asked DEI to explain if there were any units in its system that had a majority of hours with actual economic losses. While DEI did not provide a direct answer, it did provide data on hourly unit production costs and hourly MISO market revenues.[39] My analysis on this data revealed the following:

- DEI over-forecasted the net revenues from units it designated as Must Run by $7.2 million.
- This discrepancy was largely driven by Cayuga 1, Edwardsport, and Gibson 2. The table below illustrates this.
- Even if the outage at Cayuga 1 on November 13 were removed, there would still be a significant over-forecast of approximately $4 million.

[39] Duke Response and Attachment to CAC Data Request 4.14 (included as Attachments EB-2, EB-14-Confidential, and EB-15-Confidential).

Confidential Table: Comparison of DEI's forecasted net revenues with actual net revenues for generation units during periods designated as must run designations

Unit	Net Revenues from Daily P&L Forecast (Must Run periods only)	Actual Net Revenues (Must Run periods only)	$ Under/(Over) Forecast of Net Revenues
Cayuga 1	[redacted]	[redacted]	[redacted]
Cayuga 2	[redacted]	[redacted]	[redacted]
Edwardsport (coal)	[redacted]	[redacted]	[redacted]
Gibson 1	[redacted]	[redacted]	[redacted]
Gibson 2	[redacted]	[redacted]	[redacted]
Gibson 3	[redacted]	[redacted]	[redacted]
Gibson 5	[redacted]	[redacted]	[redacted]
Total	**$3,113,703**	**-$4,098,571**	**-$7,212,274**

Q. Do you believe the costs provided by DEI in its response and attachments to CAC Data Request 4.14 account for all of the operating costs incurred at these generating units?

A. No. In comparing the response and attachments to CAC Data Request 4.14 to the limited number of days DEI provided in its supplemental response and attachments to CAC Data Request 4.8,[40] I noticed that CAC 4.14 did not appear to include unit startup costs that

[40] DEI Response and related Confidential Attachments to CAC Data Request 4.8 (included as Attachments EB-2, EB-10-Confidential, EB-11-Confidential, EB-12-Confidential, and EB-13-Confidential). Note that CAC 4.8 includes hourly data source from the P&L Analyzer tool that DEI uses to conduct hindsight analysis of its generator performance in the MISO market, whereas CAC 4.14 includes hourly production cost and MISO revenue data, although its precise origin is not clear.

were reflected in the Daily P&L data from CAC 4.14. Thus, if anything the over-forecasting of net revenues described above is a conservative estimate.

Q. What do you conclude from this analysis?

A. Not only does DEI's Daily P&L forecast analysis routinely project significant economic losses at some of its plants, its projections are often less than the actual net revenues realized. In other words, DEI is routinely underestimating the economic losses, or overestimating the economic benefits, that occur at units that are designated as Must Run. Thus, to the extent that the Daily P&L forecasts reveal that DEI has been operating its plants imprudently, the ultimate harm to customers is even greater than these forecasts would suggest. Moreover, this means that DEI's unit commitment decisions are likely biased in favor of Must Run designations since the Company's forecasts are overly optimistic.

Q. What does this suggest for potential remedies, such as a disallowance of FAC costs?

A. If anything, the Daily P&L forecasts should be considered a lower bound in terms of any potential disallowance since the harm to customers from DEI's decisions is even greater than what DEI predicted. While it may be reasonable to not hold DEI responsible for a loss that is entirely unexpected, where the Company commits a unit as Must Run despite its own forecast that such commitment would lead to an economic loss, it is reasonable to require Duke to shoulder the entire economic loss that was actually experienced.

2) <u>Impact of forced outages</u>

Q. Please describe the unplanned outages at the Cayuga plant during the FAC 123 reconciliation period.

A. There were four outages at Cayuga 1 and 2 during September through November 2019.[41]

Table 4: Cayuga Outages during September through November 2019

UNIT	EVENT TYPE	EVENT START	EVENT END	EVENT DESCRIPTION
CAYUGA 1	Unplanned Outage	11/13/19 6:00 AM	11/17/19 1 2:00 PM	West Side of Boiler, 3rd Floor Tube Leak
CAYUGA 1	Maintenance outage	11/17/19 12:00 PM	11/17/19 12:21 PM	Reverse Power Relay Testing
CAYUGA 2	Maintenance Outage	9/5/19 4:00 PM	9/14/19 2:06 PM	Transition to maintenance outage for repairs to hp turbine throttle valve #2
CAYUGA 2	Unplanned Outage	10/1/19 8:15 AM	10/4/19 9:15 AM	Off-line due to high downstream river temp

Q. Please explain the economic impact to DEI customers from the Cayuga unplanned outages.

A. The economic impact of the unplanned outage on November 13, 2019 is described in Mr. Swez's testimony pages 24-25. When the unit came off in the Real-Time market based on a Must Run commitment offer,[42] it was required to "buy-back" its Day-Ahead award with a charge called the Real-Time Non-Excessive amount. This single event resulted in a loss

[41] DEI Response and Confidential Attachments to CAC Data Request 8.3 (included as Attachments EB-2, EB-27-Confidential, EB-28-Confidential, EB-29-Confidential, and EB-30-Confidential).
[42] DEI Response to CAC Data Request 4.15 (included as Attachment EB-2).

of $3,207,845 due to the very high Real-Time LMP. The second unplanned outage during the first days of October resulted in lower losses, because the unit did not have a Day-Ahead award and was thus not required to "buy-back" the amount. In fact, the outage essentially took an uneconomic unit out of operation.

Q. Please describe the unplanned outages at the Edwardsport plant during the FAC 123 reconciliation period.

A. I have not reviewed data covering the entire FAC period. However, DEI provided a list of all events as recorded in the Company's North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) for Edwardsport for the dates of September 5-8, 2019 and September 18-21, 2019.[43]

Confidential Table 4: Edwardsport events for the dates of 9/5-8 and 9/18-21

EVENT TYPE	EVENT START	EVENT END	EVENT DESCRIPTION
[redacted]			

[43] DEI Confidential Attachment CAC 4.8-A (included as Attachment EB-10-Confidential).

[redacted]

Q. Please explain the economic impact to DEI customers from the Edwardsport unplanned outages.

A. The 9/7/2019 outage led to a requirement to buy back energy in the Real Time Market with losses of approximately $[redacted].[44] On 9/20/2019, those losses were approximately $[redacted]. It is worth noting that in these cases the buy back energy costs were actually less than the economic losses incurred when the plant was operation. Thus, the outages at Edwardsport actually saved customers money.

Q. Given that the outages you focused on were unplanned, how is understanding the cost impact relevant to this proceeding?

A. Understanding the cost impact of outages combined with the probability of such outages is not only relevant, but also important within this and future FAC proceedings. A continued history of outages that lead to significant losses should inform future dispatch decisions. DEI claims that it periodically reviews the risk of Real-Time operations

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[44] See my workpaper.

through the P&L Analyzer, but has not explained how this analysis is used to inform future decisions.

Q. How could the P&L Analyzer results inform future dispatch decisions?

A. If one of the units tends to have outages that are coincident with Real-Time price spikes, as it might be the case for Cayuga, then continuing to operate this unit – especially as Must Run - exposes customers to increased risk of Real-Time price exposure, such as what occurred on November 13, 2019. Even if these units were shown to be typically "in the money," periodic outages would increase the overall cost to customers over multiple FAC periods and worsen their overall economics. As such a risk premium should be added to the Daily P&L Analysis to reflect this. DEI is not only choosing not to include a risk premium, but furthermore keeps committing those units as Must Run, thereby increasing the hours they are operating and consequently increasing the risk of outages and associated costs for customers.

Q. What is your recommendation for managing this risk and mitigating cost impacts for DEI customers?

A. I recommend that DEI adjust its Daily P&L analysis to account for the general outage rates of each unit, realizing that forcing units with high outage rate to operate as Must Run (and thus more frequently), could also increase the frequency of unplanned outages and therefore costs for customers.

Q. Were you able to identify the historical outage rates of DEI's generating units that could inform our understanding of the general outage rates for future FAC periods?

A. No. DEI objected to providing any information on outage rates outside of the FAC 123 period.

C. DEI frequently designates units as Must Run rather than Economic even when it considers those plants to be marginal or "at the money"

Q. Does DEI have specific numeric criteria for when a unit is "in the money" and could be safely committed as Must Run versus "at the money" and should be committed as Economic?

A. This does not appear to be the case. When asked, DEI replied that "There is no specific 'numerical range.'"[45]

Q. Did DEI provide a list of the units it considered to be marginal or "at the money" for each week in the FAC 123 period?

A. Yes.[46]

Q. In your opinion, what would be the most logical unit commitment status for units that are marginal or "at the money"?

A. Economic. This is true especially for units that are offline. Since there is a substantial likelihood that the net revenue from these units will be small, or even negative, there is a great risk that they will not recover their startup costs. This risk is largely eliminated if committed as Economic due to MISO Make Whole payments.

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[45] Duke Response to CAC Data Request 2.13 (included as Attachment EB-2).
[46] Duke Response to CAC Data Request 2.14 (included as Attachment EB-2).

V. Plant Specific Concerns

A. Edwardsport nearly always operates as Must Run even though it is typically "out of the money"

Q. Do you believe that DEI's unit commitment and dispatch decisions for Edwardsport during the FAC 123 period were prudent?

A. No. In fact, I believe the pattern demonstrated for the FAC 123 period calls into question whether Edwardsport has been operated prudently during any previous FAC period or will be operated prudently in any future FAC period.

Q. Can you elaborate on why the pattern of operations at Edwardsport is imprudent?

A. As I stated earlier, Edwardsport was operated nearly continuously (98% of total hours), using coal as a primary fuel source, except for brief outages on 9/7/19 and 9/20/19. This is true despite DEI's own Daily P&L forecast showing economic losses occurring (at the expense of DEI customers) during the majority of the time. Meanwhile, those same Daily P&L forecasts also demonstrated that it was more economic to operate Edwardsport on natural gas [redacted]% of the time; however, DEI chose not to do so. Operating Edwardsport on natural gas, as DEI's Daily P&L forecasts suggested, would not only have avoided $4.9 million in actual economic losses, but it could have realized about $3.0 million in additional economic benefits which is what DEI predicted during this short three month timeframe. As a result, the total reduction in the FAC that customers would have realized from switching to gas would have been $7.9 million, or $3.0 million in unrealized economic benefits plus $4.9 million in avoided economic losses.

Q. How long does DEI plan to operate the Edwardsport plant?

A. According to their 2018 IRP, the plant's lifetime is currently through 2045.

Q. Assuming the economic losses (and foregone benefits) you identified above for FAC 123 are representative of future FAC periods and that market conditions are similar, what would be the total impact to customers over the plant's lifetime?

A. I estimate that DEI customers could pay an additional $700-800 million more than necessary if Edwardsport continues to operate in the same way going forward. Note that this is simply a rough estimate based on what I observed in the FAC 123 period. A more complete analysis that takes into account changing market conditions and seasonal variations over time would be warranted. That said, I do not anticipate the fundamental performance of Edwardsport to improve relative to competing generators in the MISO marketplace.

Q. Has DEI conducted any analysis to evaluate the costs and benefits to its customers of operating Edwardsport on natural gas going forward?

A. No.[47] However, the fact that DEI's Daily P&L Forecasts clearly demonstrate that Edwardsport would be more profitable to run on gas [redacted]% of the time suggests that such an analysis may not even be needed since the advantage is so obvious.

Q. Has DEI admitted that it may be more economic to operate Edwardsport on natural gas?

A. Partially. DEI states that, "At times, the Daily Profit & Loss Analysis that the Company

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[47] DEI Response to CAC Data Request 4.16 (included as Attachment EB-2).

uses to inform its commitment offer does suggest cycling the station to natural gas for short periods of time."[48] However, this statement is somewhat misleading since this fact appears to be true [redacted] within the FAC 123 period, rather than only for "short periods of time." Moreover, DEI admits that it has not done any analysis to determine whether this may also be true over a longer time horizon beyond this FAC period.[49]

Q. Has DEI provided other rationales for operating the plant using the coal gasifiers and as a Must Run unit?

A. Yes. The Company enumerated additional reasons in direct testimony and in response to CAC Data Request 2.32.[50]

Q. Do you find these additional reasons to be compelling?

A. No. I address each of these paraphrased DEI rationales and provide my response to them in the table below.

Table 5: DEI rationales for Offering Edwardsport with a Must-Run Status and Rebuttal Arguments

DEI Rationales in CAC Data Request 2.32 for Operating Edwardsport on Coal as Must Run	**Response**
i. Cycling Edwardsport would increase forced outage rate, causing lower capacity value for MISO capacity auction	• DEI has neither estimated this lower capacity value nor demonstrated that it would exceed the plant's economic losses. • Cycling effects would be minimized if Edwardsport were simply operated less frequently.
ii. Gasifiers have a 14-day cycle time requiring the plant to stay online	• DEI's 2-week ahead and 3-week ahead Daily P&L forecasts for Edwardsport also showed [redacted] in all but one week.

[48] Duke Response to CAC Data Request 2.32 (included as Attachment EB-2).
[49] DEI Response to CAC Data Request 4.16 (included as Attachment EB-2).
[50] DEI Response to CAC Data Request 2.32 (included as Attachment EB-2).

iii. De-committing gasifiers would cause loss of essential personnel	• Steps could be taken by DEI to minimize harm to any essential personnel. • Retention of personnel has no bearing on the economic prudency of plant operations.
iv. Even though switching to gas may be more economic, this cannot be done only for short periods	• DEI's Daily P&L analysis shows that this would be prudent [redacted] of the time, so cycling off for longer periods should be considered.
v. Operating on gas may require additional firm gas transportation costs	• DEI has neither estimated what these costs would be nor demonstrated that they would exceed the plant's economic losses.
vi. Switching to gas would eliminate the diversity value of the plant	• The plant currently has very limited diversity value since DEI chooses to operate it only with coal as the primary fuel source. • Coal already comprises roughly half of DEI's fuel expenditures. Thus adding or maintaining coal resources does not meaningfully contribute to diversity.
vii. The plant permits contemplated coal being the primary fuel source	• DEI could pursue new or revised permit applications (presuming such revisions are even necessary).
viii. Operating solely on gas is shortsighted	• This is a vague statement and it is unclear what long-term value is being considered.

Q. Might DEI have other incentives to choose its current approach to operating Edwardsport, which the Company may not have stated?

A. Yes. The fact that Edwardsport is so uneconomic to operate calls into question the prudency of Duke's stated plan to continue operating the plant in the same way for decades. As such, DEI may be biased towards operating the plant nearly continuously on coal syngas as a way to prove its usefulness and avoid any potential risk of disallowed fixed cost recovery. However, this is not in the best interest of DEI's customers.

B. DEI's Cayuga Steam Contract Creates Ratepayer Losses from Uneconomic Unit Commitment

1) <u>Overview of the Company's Steam Provision to International Paper</u>

Q. Describe the contract between DEI and International Paper.

A. DEI provides high pressure steam to paper product manufacturer, International Paper, under a contract initially executed in 1974.[51] The contract has since been updated several times under Commission approval. The current contract, the Fourth Amendment to the Third Supplemental Agreement, was approved in 2012.

Q. How does the Company provide steam to International Paper?

A. The Company's Cayuga generating facility supplies the steam. The facility has two generating units, at least one of which must always be online to ensure steam supply to this one customer, regardless of whether it would otherwise be used in the energy market.

Q. Have the economics of Cayuga Station changed since the approval of the current steam contract in 2012?

A. Yes. While the Commission may have found the contract provisions to be "reasonable and just, practicable and beneficial to the parties" in early 2012,[52] the grid resource mix and underlying economics have changed significantly since then, frequently causing Cayuga's operation to be uneconomic at prevailing MISO market prices. Over eight years later, the contract does not properly address the frequent uneconomic operations of

[51] *See* Petitioner's Ex. 3-A.
[52] Petitioner's Ex. 3 (Diaz Direct), pp. 3-4.

units such as these and their resulting costs to customers.

Q. Can a Cayuga unit generate only the amount of steam necessary to serve the steam customer?

A. No. Steam service to International Paper is equivalent to 20 MW of generator output,[53] but the minimum load of a Cayuga unit providing steam service is about 320 gross MW output. The minimum load without steam service is about 230 net MW.[54] Thus, if a Cayuga unit is online solely to serve the steam customer, but is uneconomic otherwise, it will be overdispatching by about 300 MW and creating corresponding economic losses if Cayuga is out of the money.

Q. Why is Cayuga unit's minimum load 70 MW higher when providing steam service?

A. The increased minimum load is due to a technical relationship between steam flow and the turbine reheater. Evidently, "the minimum load while providing steam service was based on a recommendation…when the steam service originally went into service in the 1970s."[55]

Q. How does DEI ensure that the Cayuga station always provides steam to International Paper?

A. To ensure that a Cayuga unit constantly provides steam – in other words, that a unit is always online with output above 300 net MW – the Company always offers one of the

[53] Petitioner's Ex. 3 (Diaz Direct), p. 9.
[54] Duke's Response to CAC Data Request 2.29 (included as Attachment EB-2).
[55] Duke's Response to CAC Data Request 2.29 (included as Attachment EB-2).

Cayuga units with a commit status of Must Run in MISO.[56] Thus, at least one Cayuga unit is committed as Must Run 100% of the time - unless both units are experiencing an outage - regardless of its economic competitiveness. This means that it may cost the Company more to generate power for steam than the Company is going to earn for that power in the MISO market. As a result, running a Cayuga unit to produce steam frequently causes a financial loss for DEI in the MISO market – but the Company still commits the unit in order to serve its steam customer's needs.

2) <u>Negative Impacts to Ratepayers</u>

Q. Does the need to always run a Cayuga unit pose a financial risk to DEI's electric customers?

A. Yes. All electric customers are held responsible for the aforementioned financial losses. The fuel costs for running the Cayuga unit are recovered through the FAC while other production costs (O&M, emissions, etc.) are recovered through, all of which are paid by DEI's captive electric customers. MISO revenues can offset the production costs, but when generation costs exceed revenues, electric customers must pay for this difference. Thus, when DEI commits a Cayuga unit as Must Run to supply steam regardless of its economic potential in the energy market, it puts customers at a higher risk that the production cost of the Cayuga unit will exceed its MISO energy market revenues.

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[56] DEI Response and Confidential Attachment to CAC Data Request 6.4 (included as Attachments EB-2 and EB-25-Confidential).

Q. Is the steam customer responsible for any financial losses resulting from electricity production at Cayuga necessary to supply steam?

A. No. Even when a Cayuga unit is online simply to provide steam to the steam customer, that steam customer is not held accountable for the full total of the unit's economic losses related to electricity generation. Thus, DEI's electric customers are effectively subsidizing the steam supply for International Paper.

Q. Did you quantify the economic losses to electric customers from running a Cayuga unit for steam supply?

A. Yes. During the FAC 123 period, I estimate that the Cayuga station yielded $1,442,490 in economic losses when committing one of its units as Must Run to supply steam.[57] This represents the total net revenue (i.e. energy and ancillary market revenues[58] minus actual variable costs[59]) for Cayuga during the hours when only one unit was operating and had a Must Run commitment status offer.

Q. Was there always at least one unit offered as Must Run during the FAC 123 period?

A. Yes, at least one unit was always offered as must-run, aside from 72 hours in October 2019 when both units experienced an outage. The Must Run frequency is attributable to the need to serve the steam customer. Most of the time, just one unit was offered as Must Run, and the other was offered as Economic, if available.

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[57] See my workpapers.
[58] Cause No. 38707 FAC 123, Duke Response to Sierra Club Data Request 1.1 and Confidential Attachment SC 1.1-M (included as Attachment EB-2 and Attachment EB-33-Confidential).
[59] Cause No. 38707 FAC 123, Duke Response to Sierra Club Data Request 1.1 and Confidential Attachment SC 1.1-H (included as Attachment EB-2 and Attachment EB-32-Confidential).

Q. Did DEI on occasions offer both Cayuga units as Must Run simultaneously during the FAC period?

A. Yes. Specifically, DEI offered both units with a Must Run commit status on three separate occasions:

1. From September 16-20, 2019, Cayuga Unit 2 joined Cayuga Unit 1 as Must Run "due to the fact that it was in the money."[60] The Daily Profit and Loss Analysis forecasted it to have a margin on each day of the period that far exceeded the cold startup cost. Indeed, each unit earned a profit.
2. On November 1, 2019, Cayuga Unit 2 joined Cayuga Unit 1 as Must Run because of a safety concern ("hot spots") that required burning the coal out of the bunkers.[61] Both units lost money during this day.
3. From November 7-13, 2019, Cayuga Unit 2 joined Cayuga Unit 1 as Must Run because it "was forecast to be significantly in the money" and was expected to create $488,141 in value.[62] Indeed, Cayuga Unit 2's revenues exceeded costs by [redacted][63] during that period.

It is worth noting that based on DEI's approach to unit commitment, it would have likely committed both units as Must Run during the first and third occasions listed above regardless of the steam contract. That is, from September 16-20, 2019, and November 7-13, 2019, both units were found to be significantly "in the money" which is when DEI

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[60] Duke Confidential Response to CAC Data Request 8.1 (included as Attachment EB-3-Confidential).
[61] Duke Response to CAC Data Request 2.37 (included as Attachment EB-2).
[62] Duke Response to CAC Data Request 2.38 (included as Attachment EB-2).
[63] See my workpaper.

typically selects a Must Run status. As such, I do not believe these instances of Must Run status are attributable to the steam customer.

Q. Can you summarize the net revenues during all the hours Cayuga was designated as Must Run during the FAC 123 period and also during each of these three occasions listed above?

A. Yes, please see the confidential table below.

Confidential Table 7. Cayuga Net Revenue during Must Run Hours during the FAC 123 period[64]

	Periods when at least one Cayuga unit was Must Run	***Periods when both Cayuga units were Must Run***	***Periods when only one Cayuga unit was Must Run (i.e. attributable to steam customer)***
	A	**B**	**A - B**
Cayuga 1	[redacted]	[redacted]	$ (896,467)
Cayuga 2	[redacted]	[redacted]	$ (546,023)
Total	$(1,165,805)	$ 276,685	$ (1,442,490)

The total net revenues during all FAC 123 hours when either Cayuga Unit 1 or Unit 2 (or both) was Must Run was -$1,165,805. The total net revenues during the periods when both units were committed as Must Run was $276,685.

[64] These calculations use revenue and cost data from Confidential Attachment SC 1.1-M and Confidential Attachment SC 1.1-H (included as Attachment EB-33-Confidential and Attachment EB-32-Confidential) and can be found in my forthcoming workpapers.

Q. How did you treat these periods when both Cayuga units were offered as Must Run?

A. When both Cayuga units were designated as Must Run, I was unable to directly attribute a single unit's costs and revenues to the steam customer. Moreover, as I described, DEI likely would have committed both units as Must Run even without the steam contract because DEI commits its units as Must Run when it predicts they are economic to run or due to other rare circumstances (e.g. safety, testing, etc.). As such, I excluded these periods when calculating the economic losses that are attributable to the steam contract during the FAC 123 period. Thus, the resulting economic loss attributable to the steam customer equals -$1,442,490 (that is, -$1,165,805 for periods with a single Must Run unit less $276,685 from periods with two Must Run units). This represents the amount that DEI's electric customers will be subsidizing DEI's steam customer for the FAC 123 period as proposed in DEI's application.

Q. Why did you omit the net revenues from the periods when both units were committed as Must Run?

A. When both Cayuga units are offered as Must Run, it creates a unique circumstance in which it is no longer likely that either unit was online strictly to serve the steam customer. For example, when each unit earned over $1 million from September 16-20, 2019, their positive net revenues would have prompted DEI to commit them as Must Run regardless of its obligation to International Paper.

If a Cayuga unit is running because it needs to provide steam to International Paper when self-committing in MISO is otherwise not economic, any gains or losses are attributable to the steam contract. However, if DEI does in fact expect to make money on commitment, whether or not they need the unit for steam is irrelevant in the market context, and they are thus not attributable to the steam contract.

Q. Why did Cayuga Unit 1 lose money when Cayuga Unit 2 was expected to be "significantly in the money" in mid-November of 2019?

A. As previously mentioned, Cayuga Unit 1 lost an alarming $3.2 million in production costs and market charges in a single day on November 13, 2019, when it ramped offline due to an unplanned boiler leak.[65]

Q. Have the losses from the November 13, 2019 unplanned outage at Cayuga been included as part of the retail customer impacts of DEI's steam contract?

A. No. As discussed above, my calculation of electric market losses due to the steam customer include only the hours when one Cayuga unit was designated as Must Run. Both Cayuga units were offered with a Must Run commitment status on November 13, 2019, due to expected market gains and, therefore, the massive loss from the unplanned outage is not included in my calculation of retail customer losses. Thus, this technical outage plays no part in the total $1,442,490 retail customer loss due to Duke's steam contract with one steam customer.

Q. Does Duke quantify or address the significant losses in the energy market incurred from running a Cayuga steam unit to supply the steam customer?

A. No. Duke acknowledges that it has not studied whether the revenues from the steam

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[65] Petitioner's Ex. 1 (Swez Direct), p. 24.

contract are sufficient to offset the MISO market losses from uneconomic operation of the Cayuga unit used to provide the steam.[66]

Q. Does DEI assert that anything could make up for these significant losses being passed to retail customers?

A. Yes. DEI asserts that retail customers benefit from the steam contract in various ways including: demand revenues for steam supply are passed to electric customers, the "fixed cost contribution from International Paper which reduces overall recovery from retail electric consumers,"[67] and the jobs and diversified DEI portfolio enabled by the steam contract.

Q. Are these benefits significant compared to the retail losses?

A. No. DEI touts that steam demand revenues were voluntarily shared with retail electric customers; however, the sharing mechanism effectively accounts for the fact that the steam customer has long underpaid the demand costs associated with steam service.[68] Indeed, once the allocation of demand costs is rectified in the pending base rate case, the cost sharing mechanism will discontinue.[69] Thus, while the sharing mechanism improved an allocation imbalance caused by the time between infrequent DEI rate cases, the

[66] Duke Response to CAC Data Request 2.27 (included as Attachment EB-2).
[67] Petitioner's Ex. 3 (Diaz Direct), p. 13.
[68] Witness Birnbaum testified in Cause No. 44087 that "[redacted] *See* Confidential Attachment CAC 2.17-A, p.17 (included as Attachment EB-9-Confidential).
[69] DEI Witness Diaz confirms that, "as a result of the conclusion of the pending base rate case, updated costs assigned to steam supply for the test period are removed from the setting of base rates for retail electric customers such that the retail customers will benefit from the allocation of steam supply costs." Duke's Response to CAC Data Request 4.38 (included as Attachment EB-2).

$50,000 voluntary contribution every FAC period[70] does not offer retail electric customers a significant additional benefit when compared to the far greater amount of energy-related economic losses that are likely in the millions each FAC period.

Furthermore, the steam customer's fixed cost contribution, which is described in DEI's direct testimony,[71] should not be construed as an incremental benefit to retail customers because it simply reflects cost causation. International Paper covers its demand-related fixed cost responsibility by paying for the amount of capacity that it uses when it extracts steam from the Cayuga station. That steam and its electrical capacity are therefore precluded from retail customer use and the fixed costs for providing that capacity should certainly not be borne by retail customers. Thus, this is not an additional benefit to electric customers in excess of what the steam customer should already be paying based on the principles of cost causation.

With regard to the claimed customer benefits from job creation and DEI's diversified sales portfolio, these are unquantifiable in the context of the FAC and thus do not offset the $1.4 million in fuel related costs of the steam contract to retail customers.

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[70] Petitioner's Ex. 3 (Diaz Direct), p. 11.
[71] Petitioner's Ex. 3 (Diaz Direct), p. 8.

3) <u>Recommended Change to FAC Cost Allocation</u>

Q. How do you recommend rectifying the ratepayer burden caused by the steam contract?

A. I recommend that the $1,442,490 in losses be removed from the FAC 123 collection from retail electric customers. Instead of collecting these costs from electric customers, DEI or the steam customer should be held responsible for the losses resulting from their contractual agreement. These losses represent the true cost of the arrangement, for which DEI and the steam customer are responsible.

Q. Why shouldn't electric customers have to pay the production costs for Cayuga units that do not exceed market revenues?

A. The Cayuga station would not have been producing in the energy market during the single-unit Must Run hours, had it not been contracted to provide an entirely different commodity to an external customer. Duke and International Paper are currently indifferent to the financial losses incurred in the energy market by their agreement because ratepayers indemnify them from the costs through the FAC.

VI. <u>General policy issues</u>

A. Inflexibility of DEI's generation fleet

Q. DEI has characterized the commitment practices of its generation fleet as providing "operational flexibility."[72] Do you agree with the notion that DEI's fleet can operate in a way that provides system flexibility?

A. Not at all. As an overarching concern, I'm surprised by the substantial *in*flexibility of DEI's generation fleet. The minimum run times for its coal units range from [redacted] (Cayuga, Gallagher), to [redacted] (Gibson), to [redacted] for Edwardsport.[73] This means DEI cannot effectively respond in real time to ever-changing MISO market conditions. It also means that DEI is ill-equipped to respond to the evolving needs of the grid as more variable generation sources are introduced. In fact, maintaining such inflexible units is in opposition to the industry trend of seeking more flexible generation sources. For example, modern inverter-based generation technologies such as battery storage, wind turbines, solar PV, and hybrid wind/solar/gas plus battery storage all have the capability of responding instantaneously (i.e. within seconds) to dispatch instructions. This stands in stark contrast to DEI's plants which require days or weeks to reach full unit commitment status.

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[72] Petitioner's Ex. 1 (Swez Direct), p. 29, line 7.
[73] Duke's Confidential Response to CAC Data Request 4.6 (included as Attachment EB-3-Confidential).

B. Incompatibility of DEI's unit commitment timeframe with the MISO market rules

Q. Are DEI's plants well suited for participation in MISO's competitive markets for energy and ancillary services?

A. No. One reason why DEI so frequently resorts to Must Run unit commitment status is that the MISO Day-Ahead market model cannot even accommodate units with a minimum run time of longer than 24 hours. Ideally, there would be no need for any utility to offer units as Must Run except under rare circumstances. As has been pointed out in a recent analysis by Southwest Power Pool ("SPP"),[74] frequent use of the Must Run status can actually lead to economically inefficient outcomes, and undermines the general function of competitive markets. The fact that MISO has not even developed market rules for longer run times speaks to the fact that DEI's units are ill-suited for participation in modern power markets.

[74] Southwest Power Pool, Inc., Market Monitoring Unit, *Self-committing in SPP markets: Overview, impacts, and recommendations* (Dec. 2019) (available at https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf).

C. Coal contracting and its relation to dispatch decisions

Q. Do you have any concerns regarding DEI's coal contracting practices and its relation to unit commitment and dispatch decisions?

A. Yes. I am concerned that DEI's contracting practice is leading to coal oversupply, which is distorting its unit commitment practices and leading to higher costs for customers. In fact, the problem has worsened to the point that DEI has recently reinstated coal decrement pricing in an effort to burn more coal.

Q. Did DEI have a significant coal oversupply problem during the FAC 123 period?

A. Yes. In its most recent rate case, DEI contended that it manages its coal supply to target having approximately 45 days of coal at full load burn stored at its plants (note also that DEI's plants do not typically operate at full load).[75] However, by the end of the FAC 123 period, Nov. 30, 2019, DEI had 60 days of coal - or 3,245,125 tons - stored at its plants.[76] This is an increase of 12% from the on-site 53 days of coal inventory - 2,905,824 tons - at the end of the FAC 122 period, August 31, 2019.[77] According to DEI's Response to CAC Data Request 2.1, DEI's on-site coal inventory has increased from 2.9 million tons at the beginning of the period to 3.2 million tons at the end of the period – a 12% increase.[78] In addition, DEI had approximately 787,660 tons of coal

[75] Cause No. 45253, Petitioner's Ex. 22 (Phipps Direct), p. 6.
[76] Cause No. 38707 FAC 123, Petitioner's Ex. 4 (Phipps Direct), p. 8, lines 1-4.
[77] *Id.* p. 7, lines 19-21.
[78] Cause No. 38707 FAC 123, Petitioner's Ex. 4 (Phipps Direct), p. 7; DEI Confidential Response to CAC Data Request 2.1 (included as Attachments EB-3-Confidential).

stored off-site at the end of the FAC 123 period.[79]

Q. Has DEI's coal oversupply problem increased since the FAC 123 period?

A. Yes. In his testimony in DEI's FAC 124 filing, Mr. Phipps stated that as of February 29, 2020, DEI had a 67-day supply of coal – 3,635,324 tons - in its on-site inventory.[80] In addition, DEI's off-site coal storage level had increased to 1,243,021 tons.[81] By April 2020, DEI had more than 5 million tons of coal stored on- or off-site combined.[82] This is more than double the 2,287,084 tons of coal inventory that DEI had as of January 2019.[83]

Q. Is DEI's coal oversupply problem only a recent phenomenon?

A. It appears not. While I have not reviewed data regarding the Company's actual coal inventory levels before 2019, I would note that DEI stored excess amounts of coal in off-site locations in 2012 and 2013.[84] In addition, the Company used coal decrement pricing in an effort to try to burn off excess coal in at least 2012, 2015, and 2016, and possibly in 2013 and 2014 also.[85] And, in both 2018 and 2019, DEI deferred to future years the delivery of coal that it had contracted to purchase in those years.[86] Each of these actions by DEI suggest that coal oversupply has been a persistent problem for the Company for many years.

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[79] Cause No. 38707 FAC 123, Petitioner's Ex. 4 (Phipps Direct), p. 8, lines 10-12.
[80] Cause 38707 FAC 124, Petitioner's Ex. 4 (Phipps Direct), p. 8.
[81] Cause 38707 FAC 124, Petitioner's Ex. 4 (Phipps Direct), p. 8.
[82] Cause No. 38707 FAC 124, Public's Ex. 2 (Eckert Testimony), p. 4.
[83] Cause No. 38707 FAC 124, Public's Ex. 2 (Eckert Testimony), p. 4.
[84] Cause No. 45253, Hearing Tr. F-78 lines 7-17; Cause No. 38707 FAC 96 Final Order, p. 3 (Oct. 30, 2013).
[85] Cause No. 45253, Petitioner's Ex. 51 (Swez Rebuttal), p. 27; Cause No. 45253, Hearing Tr. J-40, lines 5–25.
[86] Cause No. 45253, Hearing Tr. F-49 to F-50.

Q. Is there evidence to suggest that DEI is procuring more coal than it needs?

A. Yes. In DEI's most recent rate case, the Company disclosed in discovery that it was contractually hedged to purchase 103% of its projected coal burn for 2020,[87] which appears to have been based on an October 2019 projection that DEI would burn 11.6 million tons of coal in 2020.[88] By December 2019, however, the projected 2020 coal burn had declined to approximately 10.4 million tons, which meant the Company was then contractually hedged to purchase 120% of its projected coal burn in 2020.[89] By February 2020, DEI's projected coal burn for 2020 had declined to 6.5 million tons.[90]

Q. Did DEI burn less coal than it projected during the FAC 123 period?

A. Yes. DEI's projections for coal burn have far exceeded the actual burn during the FAC 123 period, resulting in a steadily growing inventory for each month.[91] The total overforecast for the FAC 123 period was about 224,000 tons or about 10%. I expect this trend to be continuing for subsequent FAC periods.

Q. Did Duke take any measures to reduce the coal inventory at its plants during the FAC 123 period?

A. Yes. In November 2019, DEI deferred the delivery of 1.4 million tons of coal from the FAC 123 period to future deliveries in 2020 and 2021.[92] Duke also continued to store increasing amounts of coal at offsite storage locations, and was storing 787,600 tons of

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[87] Cause No. 45253, Duke Response to CAC Data Request 31.9 (included as Attachment EB-2).
[88] Cause No. 45253, Hearing Tr. F-34.
[89] Cause No. 45253, Hearing Tr. F-40, F-44.
[90] Cause No. 38707 FAC 123, Public's Ex. 2 (Eckert Testimony), p. 7.
[91] Duke Response to CAC Data Request 4.27 (included as Attachment EB-2).
[92] Cause No. 38707 FAC 123, Duke Response to CAC Data Request 1.6 (included as Attachment EB-2).

coal at such locations by the end of the FAC period.[93] I would note that, while these measures decreased the amount of coal onsite at Duke's plants, they did not decrease the overall amount that Duke is obligated to purchase.

Q. Did DEI contract during the FAC 123 period to purchase additional amounts of coal, despite its growing oversupply?

A. As part of negotiating the above-mentioned deferral, DEI contracted to purchase an additional 1 million tons of coal – 500,000 tons in each of 2020 and 2021.[94] In addition, in September 2019, DEI issued an RFP for additional coal purchases, which led the Company to verbally commit in late 2019 to purchase an additional 500,000 tons of coal in 2020.[95]

Q. Did DEI say why it issued an RFP for additional coal purchases and committed to purchasing and additional 500,000 tons of coal in 2020?

A. Yes, when asked why Duke proceeded with contracting for an additional 500,000 tons of coal in late 2019 despite declining coal burns and projected oversupply of coal in 2020, Duke Witness Phipps noted that the coal companies at issue were "financially struggling."[96] When asked about this statement, Mr. Phipps testified that it was a matter

[93] Cause No. 38707 FAC 123, Petitioner's Exhibit 4 (Direct Testimony of Brett Phipps), p. 8, lines 10-12. These two offsite storage locations are both located at the mines of one of DEI's coal suppliers. Tr. F-77, lines 5-7; Conf. Response to CAC Data Request 1.5, Confidential Attachments 1.5-A and 1.5-B (Attachments EB-3-Confidential, EB-6-Confidential).
[94] Cause No. 38707 FAC 123, Duke Response to CAC Data Request 1.6(d) (included as Attachment EB-2); Confidential Response 1.3 and related Attachment 1.3-A (included as Attachment EB-Confidential) (contract for deferment).
[95] Cause No. 38707 FAC 123, Duke Response to CAC Data Request 1.8(a), (c) (included as Attachment EB-2).
[96] Cause 45253, Hearing Tr. F-51, lines 1–15.

of "supplier diversity," and because, if there are only one or two suppliers remaining, "it is more challenging to negotiate lower prices."[97]

Q. Do you believe that Duke's stated reasons for entering into new contracts for coal purchases while already oversupplied with coal are valid or appropriate?

A. I do not believe that a concern about supplier diversity was a valid basis for purchasing new coal in this instance. Mr. Phipps testified that they typically solicit roughly 25 suppliers for coal.[98] This number represents quite a large pool of suppliers, in my experience, so I do not believe that supplier diversity is an appropriate basis for Duke's customers to bear the cost of these coal purchases, nor any resultant costs related to coal oversupply. If the primary reason for this purchase is, as Mr. Phipps testified, to support a struggling supplier, that would be great cause for concern. It is wholly inappropriate to charge to Duke ratepayers for costs associated with bailing out an uncompetitive coal supplier.

[97] *Id.* Tr. F-51, line 20 to F-52, line 2.
[98] *Id.* Tr. F-63, lines 4-14.

D. General concerns regarding fuel clause cost recovery

Q. At a high level, what are the specific policy concerns you have related to fuel adjusters like the FAC?

A. Since fuel adjusters like the FAC often provide a true-up on a relatively frequent basis (e.g., quarterly), they tend to shift the risk associated with fuel and operating costs from utilities to their customers, absent rigorous commission oversight. As such, these adjuster mechanisms largely insulate the utility from exposure to fuel price risk, regardless of what may be most economic for customers. Additionally, they may dilute the incentive for utilities to pursue more economic fuel and purchase power options on a near-term basis since cost recovery of these expenses is more or less guaranteed in a timely manner. Finally, as explained throughout my testimony, the adjuster segregates long- and short-term planning, which can reduce flexibility in the near term and lead to a lock-in to suboptimal fuel decisions.

Q. Do fuel adjusters like the FAC provide a good incentive to utilities like DEI to be aligned with the public interest?

A. Not necessarily. Without rigorous Commission oversight, these types of adjusters could be passing on costs to customers that are not prudent or adequately justified.

Q. Are there any recent examples where uneconomic fuel costs have been passed on to customers through mechanisms like these?

A. Yes. There are several. Uneconomic dispatch has been most notably observed in relation to the “self-scheduling” practices of coal facilities owned by vertically integrated utilities that also operate in wholesale markets such as MISO and the SPP. Specifically, because rate regulated utilities have the opportunity to recover costs through rate cases and fuel adjustment proceedings like the FAC, the regulated utilities have less of an incentive to operate cost effectively relative to the market. There are several ways in which this can happen: a utility might submit a bid to an energy market that is less than its actual cost of production at a generating unit; a utility can elect to commit a unit to operate irrespective of projected market power prices; or a utility can schedule the full dispatch of a unit irrespective of projected market power prices. In each of these cases, a generator may receive market revenue insufficient to cover its production costs, but simply passes on excess costs to captive ratepayers through rate recovery.

Two organizations recently reported on a trend that regulated utilities frequently engage in uneconomic dispatch of coal plants and pass these costs along to ratepayers. The Market Monitoring Unit of the Southwest Power Pool found that increased self-commitment leads to a distortion of market prices and investment signals, and leads market participants to suboptimal short- and long run decisions.[99] This practice can be contrasted with operating costs and comparatively economic dispatch of merchant coal plants, that routinely dispatch less frequently and at lower average costs.

Additionally, the Union of Concerned Scientists ("UCS") recently completed a study showing that self-scheduling in MISO leads to increased costs for customers and

[99] Southwest Power Pool, Inc., Market Monitoring Unit, *Self-committing in SPP markets: Overview, impacts, and recommendations* (Dec. 2019) (available at https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf)

distorted wholesale market prices.[100] UCS also compiled a list of state proceedings (primarily fuel adjustment clauses or general rate cases) exploring the impact of uneconomic dispatch on customers in California, Iowa, Kansas, Louisiana, Michigan, Missouri, Minnesota, Texas, and Wisconsin.[101] This indicates that this practice is not only widespread, but of growing concern to state regulatory bodies.

Q. Do you believe Indiana generally strives to support fair competition in electricity markets such as through robust participation in MISO's energy markets?

A. Yes. After all, as the Commission has found, "[t]he Midwest ISO energy market offers participants the opportunity to ensure that load is served through the regional, security trained economic dispatch, which uses the most reliable and economic generator available. Customers benefit from economic dispatch. . . ."[102]

Q. Are there any considerations that should be of particular concern given Indiana's general support of wholesale electricity market competition?

A. Yes. As explained in my testimony, absent rigorous Commission oversight, the FAC essentially guarantees to DEI that its fuel costs will be recovered from uneconomic coal generators. This guaranteed recovery provides an unfair advantage to DEI's generators relative to other competitive suppliers and largely defeats the purpose of Indiana's competitive supply framework.

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[100] Joe Daniel, et al, *Used But How Useful: How Electric Utilities Exploit Loopholes, Forcing Customers to Bail Out Uneconomic Coal-Fired Power Plants* (May 2020) (available at https://www.ucsusa.org/sites/default/files/2020-05/Used%20but%20How%20Useful%20May%202020.pdf).
[101] *Id.*
[102] In re Joint Petition of Indianapolis Power & Light Co. and the Indiana OUCC for Approval of Settlement Continuing Mechanism for Recovery of Jurisdictional Costs Incurred in Connection with MISO, Cause No. 43664, Order at *6 (IURC, June 3, 2009).

Q. Would plants like Edwardsport be able to survive in a truly competitive market?

A. For plants like Edwardsport that continually operate at a loss, the only reason DEI has been able to keep operating this unit is that the Company is able to recover the plant's operating costs (e.g. fuel) from its captive customers through fuel adjusters like the FAC. If this plant were owned by a truly competitive provider (e.g. an independent power producer), it would not likely be able to continue operating in this fashion since its market revenues would not be able to fully recoup its operating costs. However, as a rate regulated utility, DEI can simply pass on the additional costs (in excess of market revenues) to its captive ratepayers. This leads to higher customer costs than if DEI were to simply purchase this power from the MISO grid.

VII. Recommendations

A. Edwardsport Disallowance

Q. Do you believe DEI customers should be required to pay for economic losses resulting from imprudent operating decisions made by DEI?

A. No. In particular, DEI ratepayers should not bear the costs of operating Edwardsport where economic losses resulted from imprudent operating decisions as I have described throughout my testimony.

Q. What remedy do you think is appropriate to make customers whole for DEI's imprudent operating choices at Edwardsport?

A. It would be appropriate to reduce the total FAC charged to customers by an amount corresponding to the economic losses that DEI incurred at the plant but which could have reasonably been avoided if the plant were not operated as a Must Run unit on coal. As explained earlier in my testimony, this loss amounts to $4.9 million for the FAC 123 period. Furthermore, it would be appropriate to further reduce the FAC charged to customers by the amount of economic benefit that was foregone by not operating the plant on natural gas. As explained earlier in my testimony, DEI estimated this foregone economic benefit to be approximately $3.0 million for the FAC 123 period. Adding these two components, I recommend a total reduction in FAC 123 charges of $7.9 million associated with Edwardsport.

B. Cayuga steam customer cost allocation for must run status for steam when the Daily P&L is negative

Q. What recommendations do you have regarding the Cayuga steam issue?

A. As outlined earlier in my testimony, I recommend that any economic losses from electricity generation that resulted from the need to commit a Cayuga unit as Must Run to serve DEI's steam customer should not be allocated to all retail electricity customers. Instead, these losses should be reallocated to either DEI or the steam customer. For the FAC 123 period this amounts to $1,442,490.

Q. Could the contract between DEI and the steam customer be amended to reflect this?

A. Yes.

C. Commission guidance on DEI operations on going forward

Q. In addition to these remedies for the FAC 123 period, do you have other recommendations on guidance the Commission should provide for future FAC periods?

A. Yes. There are several areas where I think Commission guidance is warranted and would help to ensure utility operating decisions minimize costs for customers. I have described each of these below.

1) <u>Unit commitment decision reporting requirements and FAC adjustments</u>

For each FAC application, DEI should be required to provide a report that includes the following for each generating unit:

- Hourly unit commitment designation (i.e. Must Run, Economic, Unavailable)

- Rationale for each hour with a Must Run designation
- Daily P&L Analyses conducted in the week prior to any hour with a Must Run designation
- Actual Daily P&L results for each hour with a Must Run designation

If this reporting reveals that any units were committed as Must Run while projected to have economic losses, the Commission should review the rationale for the Must Run decision. If the rationale given is not considered to be reasonable, the Commission should reduce the authorized FAC charge accordingly. In cases where the Must Run designation is related to providing steam to a steam customer, the Commission should require economic losses be assigned to the steam customer or borne by Duke.

2) <u>Coal Burn Forecasting</u>

For each FAC application that includes a forecast of future coal burn (e.g. via DEI's GenTrader or other similar forecasting tool), the forecast should be conducted without the presumption that any units will be committed as Must Run and with the presumption that the units will follow forecasted MISO market price signals. Additionally, the forecast should not include any coal decrement pricing. If actual fuel burn exceeds the forecast due to Must Run commitment status or any other reason, these amounts can be accounted for in a subsequent FAC via the reconciliation factor.

3) <u>Coal Decrement Pricing</u>

While coal decrement pricing was not used in the FAC 123 period, DEI witness Swez indicated in his FAC 124 testimony that in early March 2020 the company "started applying a coal price decrement to the dispatch costs of Gibson 1-5, Cayuga 1-2, and

Edwardsport generating units".[103] Coal decrement pricing is presented as a way to deal with excess supply in the short term. In reality, it excuses the utility's fuel procurement errors and distorts the incentives the utility has to avoid coal oversupply. In the long term, it results in higher ratepayer costs. It is important to note that this observation is not based on a hindsight analysis but aims to fix the utility's erroneous decision-making in the long-term. When projecting coal burn over the next several years to inform its coal procurement, DEI uses Must Run constraints and thereby avoids a true economic evaluation of the coal units' operations, which might reduce forecasted burn levels. DEI is aware that this hard-wiring of high burn levels via Must Run assumptions in its modeled forecasts can lead to excess coal inventories and, eventually, uneconomic dispatch once it reaches a level where a coal decrement must be implemented to avoid costs of coal oversupply. I recommend that if DEI chooses to use a price decrement in FAC 125 or other future filings, the decrement should also apply to the actual fuel costs to be recovered from ratepayers, i.e. any excessive cost that results from DEI's poor coal procurement decisions, or related modeling choices, should be borne by Duke and not by the ratepayers.

Q. Does this conclude your testimony?

A. Yes.

[103] Cause No. 38707 FAC 124, Petitioner's Ex. 6 (Swez Direct), p. 19.

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I. Summary of Findings and Recommendations

Q. Please summarize your key findings

A. My findings can be summarized as followed:

1. DEI frequently commits its coal generation units as Must Run even when they are forecasted by DEI to yield economic losses.
2. This practice is most common at the Edwardsport Integrated Gasification Combined Cycle plant which operated with a Must Run designation with coal as the primary fuel source during every week of the FAC 123 period, despite the fact that this approach was forecasted to have economic losses the majority of the time. This led to $4.9 million[1] in economic losses during the FAC 123 period that DEI has charged to its customers.
3. DEI's contract to serve one steam customer led to Must Run designations at the Cayuga plant that caused $1.4 million in higher costs to all electricity customers than they otherwise would have paid.
4. DEI routinely under-forecasts the economic losses that actually occur from plants that are given a Must Run commitment status, likely leading to a greater number of Must Run designations and higher costs to customers.
5. In its modeled forecasts to determine the amount of coal it will burn, DEI presumes Must Run status at several of its coal-burning plants, which can lead DEI to overestimate the amount of coal it will need. These forecasts in turn guide

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[1] Based on $[redacted] in MISO revenues minus $[redacted] in production costs as identified in DEI's Response to CAC Data Request 4.14, Confidential Attachments CAC 4.14-A and 4.14-B (included as Attachments EB-14-Confidential and EB-15-Confidential).

coal contract negotiations.

6. While not applicable in the FAC 123 period, DEI's assumed pricing for coal fuel sometimes includes "decrement pricing" which could distort the unit commitment and dispatch of its coal plants at the expense of its customers. DEI's coal inventories steadily increased over the FAC 123 period, leading to greater likelihood of decrement pricing being used in upcoming FAC periods.

Q. Please summarize your recommendations.

A. My recommendations are as follows:

1. The Commission should reduce the amount that DEI can collect from its customers by the amount equal to the economic losses that occur due to operating Edwardsport with coal as the primary fuel source during times when DEI predicts losses to occur but commits the plant as Must Run anyways. Additionally, the Commission should further reduce the amount collected by any foregone economic benefits that DEI predicts from operating the plant on natural gas where DEI chooses to operate the plant on coal syngas instead. These reductions total $7.9 million for the FAC 123 period.

2. The Commission should require DEI to assign the economic losses associated with Must Run designations at Cayuga to DEI or the steam customer (rather than to electricity customers) if the Must Run status was forecasted to yield economic losses and therefore presumptively attributable to the steam customer.[2] These losses total $1.4 million for the FAC 123 period. These economic losses should be assigned to DEI or the steam customer in future FAC proceedings as well.

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[2] Possible exceptions to this could include Must Run status for safety or testing needs.

P&L Analysis when making unit commitment decisions. Continuing to operate its units without accounting for this added financial risk will only lead to higher costs for ratepayers, which could potentially be avoided. The limited evidence Duke provided for the FAC 123 period points towards frequent unplanned outages at DEI's coal plants that worsen the economics of these units. I suspect that this pattern would apply to other FAC periods (and would extend into future FAC periods); however, I cannot confirm this without additional data that Duke has been unwilling to provide.

4) Post Analysis (Sumatra for Cost Allocation)

Q. Please describe the Sumatra model and its role in the FAC filing.

A. In preparation of the FAC filing, DEI also needs to determine the fuel cost allocated to serving its native load and the cost allocated to non-native load. The cost allocated to native load is recovered from DEI ratepayers through the FAC filing and the base rates. This calculation is performed with the use of a production cost model called Sumatra and in DEI's testimony it is referred as the post-analysis. The Sumatra model assigns most of the fuel costs recovered through the FAC to native load rather than non-native load.

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Q. Have you determined the MWh share of each of DEI's generators that is serving native and non-native load?

A. Yes. About 99% of the MWh output from DEI's generators operating during the FAC 123 were allocated to native load.[18] A table below shows the breakdown for each plant.

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[18] DEI Response and related Confidential Attachment to CAC Data Request 7.1 (included as Attachments EB-2 and EB-26-Confidential).

Table 2~~:~~ Native and non-native load allocation by unit

Row Labels	Native	Non-Native
CIN.CAYUGA.1	[redacted]	[redacted]
CIN.CAYUGA.2	[redacted]	[redacted]
CIN.EDWPORT IGCC		
CIN.GIBSON.1	[redacted]	[redacted]
CIN.GIBSON.2	[redacted]	[redacted]
CIN.GIBSON.3	[redacted]	[redacted]
CIN.GIBSON.4	[redacted]	[redacted]
CIN.GIBSON.5	[redacted]	[redacted]
Grand Total	**98.99%**	**1.01%**

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Q. Can you summarize the process for how all of these decision-making tools are used and how they are linked to the FAC?

A. Yes. The diagram below provides an overview of the tools and their linkages based on my understanding from conversations with DEI and evidence provided in this docket.

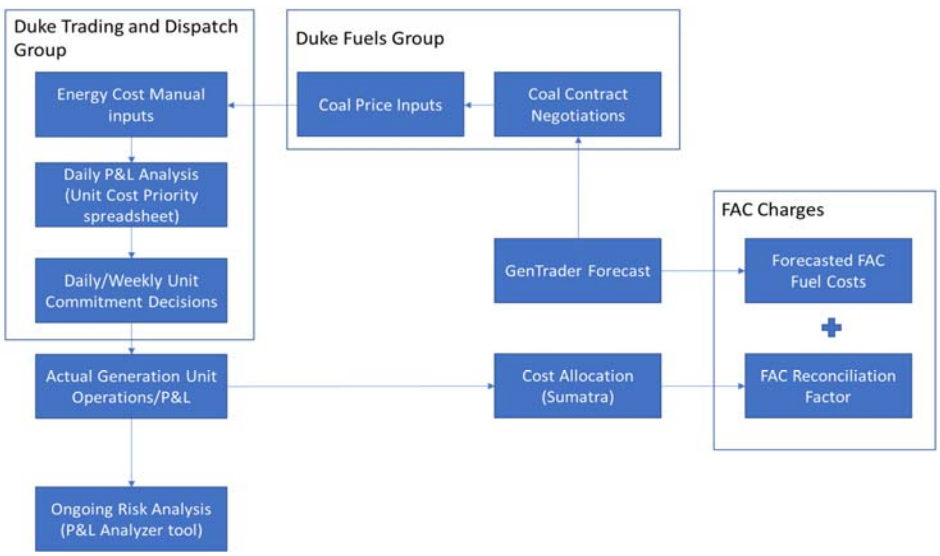

Figure 1. Overview of processes and tools used by DEI to determine unit commitment and dispatch, and their linkages to the FAC.

MISO (Cayuga 1 &2, Edwardsport, Gallagher 2 & 4, Gibson 1-5, Noblesville CC). Unit commitment decisions for each of these units for the week ahead are also notated in the data sheets.

Q. What were your findings based on this review of the Daily P&L data sheets?

A. Out of 115 total times when one of DEI's units was made available for the upcoming week (i.e. offered with a commitment status of either Economic or Must Run), I found that there were 68 instances where a unit was designated as Must Run. Of these 68 instances, 32 instances (>47%) coincided with a Daily P&L forecast for the week ahead that had a negative value (i.e. DEI expected the unit would be operating at an economic loss). DEI forecasted the total economic losses from these 32 instances to be $5.4 million.

Q. DEI claims that, in some cases, it is better to keep a plant online and incur temporary economic losses since those losses could be overcome by economic gains in subsequent days or weeks. Did you find this to be the case for the 32 instances you identified above that had a negative value?

A. For 7 of the 32 instances, the sum of the two-week ahead forecasted Daily P&L was indeed positive, despite a negative one-week ahead forecast. However, this still leaves 25 instances where even the two-week forecast showed economic losses. Moreover, these 25 instances still account for $5.1 million in week-ahead forecasted economic losses.

Q. Which plants were the largest contributors to these forecasted economic losses?

A. Edwardsport was by far the largest contributor, comprising $[redacted] million (or [redacted]%) of the $5.4 million in week-ahead forecasted economic losses. The confidential table below provides a summary of the forecasted economic gains and losses for each plant.

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Confidential Table 3: FAC 123 Expected Profits/Losses Based on DEI Daily P&L Analysis[22]

	Must Run Weeks w/ Economic Benefits (Week Ahead)		*Must Run Weeks w/ Economic Losses (Week Ahead)*		
Generating Unit	**# Weeks**	**Total**	**# Weeks**	**Total**	**% of Total $ of Forecasted Economic Losses**
CAYU_UN01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CAYU_UN02	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EDWA_CC01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GIBS_UN01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GIBS_UN02	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GIBS_UN03	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GIBS_UN05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NOBL_CC01	[redacted]	[redacted]			[redacted]
Grand Total	**36**	**$9,574,802**	**32**	**-$5,413,986**	100%

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1) *Cycling Costs*

Q. What are the cycling costs that DEI purports to factor into its analysis for determining unit commitment?

A. DEI includes both startup costs, as well as shutdown costs. It should be noted that the terms the “shutdown costs” and “wear and tear” are used interchangeably by DEI.[23] Additionally, the estimated values of these shutdown costs were based upon a 1998 EPRI paper.[24]

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[22]Duke Response to CAC Data Request 1.2, Revised Confidential Attachments 1.2-A, -B, and –C (included as Attachments EB-2 and EB-5-Confidential).
[23] DEI Response and Confidential Attachment to CAC Data Request 2.4 (included as Attachments EB-2 and EB-7-Confidential).
[24] *Id*.

Q. Do you think that some of these 38 instances where units were Must Run despite a negative P&L value might have been justified on the basis of avoiding shutdown costs?

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A. Possibly, but not in all cases. In many (but not all) of the instances involving the Gibson units, the weekly forecasted losses appear to be less than DEI's estimated shutdown costs.[25] Thus, if the unit was already online, it might make economic sense to continue operating it. However, this was not true for most of the instances involving the Cayuga units, or for all of the instances involving Edwardsport for which DEI has not identified any shutdown costs. As one example, during the week starting [redacted], Cayuga Unit 1 was forecasted to have $[redacted] in economic losses, which is far greater than the estimated shutdown cost of $[redacted] (and even greater than the combined shutdown and startup costs assumed for a full cycling which I estimate to be $[redacted]), and yet Cayuga Unit 1 was committed as Must Run. In these cases, it would have made more economic sense for DEI to offer these units with a designation of Economic rather than Must Run.

Q. Could DEI theoretically adjust its bid price to account for shutdown costs, thereby allowing it to offer its units with a designation of Economic instead of Must Run?

A. Yes. DEI could reduce its bid price to account for the fact that, to avoid the shutdown costs, it would be willing to accept a lower price for a unit, though to my knowledge this is not currently being done. Committing them as Must Run without properly accounting for the magnitude of any avoidable or non-avoidable costs is not appropriate in my

[25] Shutdown costs were provided by DEI in DEI Response to CAC Data Request 2.4 and are also included in the Daily P&L data sheets provided in DEI Response to CAC Data Request 1.2 (Attachments EB-2, EB-5-Confidential, and EB-7-Confidential).

Q. Does the economics of Edwardsport change if a similar share of natural gas is assumed as the fuel sources?

A. Assuming a 26% share of output to be powered by natural gas does improve the economics of Edwardsport. However, even under this scenario I still found that DEI's Daily P&L forecast had predicted economic losses for [redacted] weeks during the FAC 123 period and the total forecasted net revenues would be -$[redacted] million. Moreover, many of these "out of the money" weeks occurred consecutively, which suggests that DEI's commitment decision was not based upon anticipated economic gains over a longer time horizon.

Q. What were the actual net revenues for Edwardsport over the FAC 123 period?

A. In total, I found that the actual economic losses occurring from Edwardsport over the FAC 123 period were about $4.9 million, which is even greater than the losses DEI predicted in its Daily P&L forecasts as described above.

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Q. What rationale did DEI use to schedule Edwardsport as a Must Run unit in the MISO Day-Ahead Market despite these economic losses?

A. Duke provided contradictory information in its Daily P&L analysis as compared to its reasoning for operating Edwardsport as a Must Run unit.[31] According to DEI's Response to CAC Data Request 6.4, the reason given for operating Edwardsport as Must Run in

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[31] Compare Duke Responses and Confidential Attachments to CAC Data Request 2.1 to Duke Response to CAC Data Request 6.4 (included as Attachment EB-2, Attachment EB-3-Confidential, Attachment EB-25-Confidential). Notably, CAC attempted to clarify this with CAC Data Request 4.13(a), but Duke objected to providing this information (included as Attachment EB-2).

DEI does not appear to have any economically-based decision-making process for determining unit commitment status at Edwardsport.

B. DEI's Daily P&L forecasts used for unit commitment are overly optimistic and routinely under-forecast the economic losses occurring at units designated as Must Run.

1) <u>Analysis of actual daily profits/losses</u>

Q. Generally speaking, how accurate was DEI's forecasted Daily P&L relative to each plant's actual net operating revenues in the FAC 123 period?

A. CAC Data Request 4.14 asked DEI to explain if there were any units in its system that had a majority of hours with actual economic losses. While DEI did not provide a direct answer, it did provide data on hourly unit production costs and hourly MISO market revenues.[39] My analysis on this data revealed the following:

- DEI over-forecasted the net revenues from units it designated as Must Run by $7.2 million.
- This discrepancy was largely driven by Cayuga 1, Edwardsport, and Gibson 2. The table below illustrates this.
- Even if the outage at Cayuga 1 on November 13 were removed, there would still be a significant over-forecast of approximately $4 million.

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[39] Duke Response and Attachment to CAC Data Request 4.14 (included as Attachments EB-2, EB-14-Confidential, and EB-15-Confidential).

Confidential Table: Comparison of DEI's forecasted net revenues with actual net revenues for generation units during periods designated as must run designations

Unit	Net Revenues from Daily P&L Forecast (Must Run periods only)	Actual Net Revenues (Must Run periods only)	$ Under/(Over) Forecast of Net Revenues
Cayuga 1	[redacted]	[redacted]	[redacted]
Cayuga 2	[redacted]	[redacted]	[redacted]
Edwardsport (coal)	[redacted]	[redacted]	[redacted]
Gibson 1	[redacted]	[redacted]	[redacted]
Gibson 2	[redacted]	[redacted]	[redacted]
Gibson 3	[redacted]	[redacted]	[redacted]
Gibson 5	[redacted]	[redacted]	[redacted]
Total	**$3,113,703**	**-$4,098,571**	**-$7,212,274**

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Q. Do you believe the costs provided by DEI in its response and attachments to CAC Data Request 4.14 account for all of the operating costs incurred at these generating units?

A. No. In comparing the response and attachments to CAC Data Request 4.14 to the limited number of days DEI provided in its supplemental response and attachments to CAC Data Request 4.8,[40] I noticed that CAC 4.14 did not appear to include unit startup costs that

[40] DEI Response and related Confidential Attachments to CAC Data Request 4.8 (included as Attachments EB-2, EB-10-Confidential, EB-11-Confidential, EB-12-Confidential, and EB-13-Confidential). Note that CAC 4.8 includes hourly data source from the P&L Analyzer tool that DEI uses to conduct hindsight analysis of its generator performance in the MISO market, whereas CAC 4.14 includes hourly production cost and MISO revenue data, although its precise origin is not clear.

V. Plant Specific Concerns

A. Edwardsport nearly always operates as Must Run even though it is typically "out of the money"

Q. Do you believe that DEI's unit commitment and dispatch decisions for Edwardsport during the FAC 123 period were prudent?

A. No. In fact, I believe the pattern demonstrated for the FAC 123 period calls into question whether Edwardsport has been operated prudently during any previous FAC period or will be operated prudently in any future FAC period.

Q. Can you elaborate on why the pattern of operations at Edwardsport is imprudent?

A. As I stated earlier, Edwardsport was operated nearly continuously (98% of total hours), using coal as a primary fuel source, except for brief outages on 9/7/19 and 9/20/19. This is true despite DEI's own Daily P&L forecast showing economic losses occurring (at the expense of DEI customers) during the majority of the time. Meanwhile, those same Daily P&L forecasts also demonstrated that it was more economic to operate Edwardsport on natural gas [redacted]% of the time; however, DEI chose not to do so. Operating Edwardsport on natural gas, as DEI's Daily P&L forecasts suggested, would not only have avoided $4.9 million in actual economic losses, but it could have realized about $3.0 million in additional economic benefits which is what DEI predicted during this short three month timeframe. As a result, the total reduction in the FAC that customers would have realized from switching to gas would have been $7.9 million, or $3.0 million in unrealized economic benefits plus $4.9 million in avoided economic losses.

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Q. Is the steam customer responsible for any financial losses resulting from electricity production at Cayuga necessary to supply steam?

A. No. Even when a Cayuga unit is online simply to provide steam to the steam customer, that steam customer is not held accountable for the full total of the unit's economic losses related to electricity generation. Thus, DEI's electric customers are effectively subsidizing the steam supply for International Paper.

Q. Did you quantify the economic losses to electric customers from running a Cayuga unit for steam supply?

A. Yes. During the FAC 123 period, I estimate that the Cayuga station yielded $1,442,490 in economic losses when committing one of its units as Must Run to supply steam.[57] This represents the total net revenue (i.e. energy and ancillary market revenues[58] minus actual variable costs[59]) for Cayuga during the hours when only one unit was operating and had a Must Run commitment status offer.

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Q. Was there always at least one unit offered as Must Run during the FAC 123 period?

A. Yes, at least one unit was always offered as must-run, aside from 72 hours in October 2019 when both units experienced an outage. The Must Run frequency is attributable to the need to serve the steam customer. Most of the time, just one unit was offered as Must Run, and the other was offered as Economic, if available.

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[57] See my workpapers.

[58] Cause No. 38707 FAC 123, Duke Response to Sierra Club Data Request 1.1 and Confidential Attachment SC 1.1-M (included as Attachment EB-2 and Attachment EB-33-Confidential).

[59] Cause No. 38707 FAC 123, Duke Response to Sierra Club Data Request 1.1 and Confidential Attachment SC 1.1-H (included as Attachment EB-2 and Attachment EB-32-Confidential).

Q. Did DEI on occasions offer both Cayuga units as Must Run simultaneously during the FAC period?

A. Yes. Specifically, DEI offered both units with a Must Run commit status on three separate occasions:

1. From September 16-20, 2019, Cayuga Unit 2 joined Cayuga Unit 1 as Must Run "due to the fact that it was in the money."[60] The Daily Profit and Loss Analysis forecasted it to have a margin on each day of the period that far exceeded the cold startup cost. Indeed, each unit earned a profit.
2. On November 1, 2019, Cayuga Unit 2 joined Cayuga Unit 1 as Must Run because of a safety concern ("hot spots") that required burning the coal out of the bunkers.[61] Both units lost money during this day.
3. From November 7-13, 2019, Cayuga Unit 2 joined Cayuga Unit 1 as Must Run because it "was forecast to be significantly in the money" and was expected to create $488,141 in value.[62] Indeed, Cayuga Unit 2's revenues exceeded costs by [redacted][63] during that period.

It is worth noting that based on DEI's approach to unit commitment, it would have likely committed both units as Must Run during the first and third occasions listed above regardless of the steam contract. That is, from September 16-20, 2019, and November 7-13, 2019, both units were found to be significantly "in the money" which is when DEI

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[60] Duke Confidential Response to CAC Data Request 8.1 (included as Attachment EB-3-Confidential).
[61] Duke Response to CAC Data Request 2.37 (included as Attachment EB-2).
[62] Duke Response to CAC Data Request 2.38 (included as Attachment EB-2).
[63] See my workpaper.

typically selects a Must Run status. As such, I do not believe these instances of Must Run status are attributable to the steam customer.

Q. Can you summarize the net revenues during all the hours Cayuga was designated as Must Run during the FAC 123 period and also during each of these three occasions listed above?

A. Yes, please see the confidential table below.

Confidential Table 7. Cayuga Net Revenue during Must Run Hours during the FAC 123 period[64]

	Periods when at least one Cayuga unit was Must Run	*Periods when both Cayuga units were Must Run*	*Periods when only one Cayuga unit was Must Run (i.e. attributable to steam customer)*
	A	**B**	**A - B**
Cayuga 1	[redacted]	[redacted]	$ (896,467)
Cayuga 2	[redacted]	[redacted]	$ (546,023)
Total	$(1,165,805)	$ 276,685	$ (1,442,490)

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The total net revenues during all FAC 123 hours when either Cayuga Unit 1 or Unit 2 (or both) was Must Run was -$1,165,805. The total net revenues during the periods when both units were committed as Must Run was $276,685.

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[64] These calculations use revenue and cost data from Confidential Attachment SC 1.1-M and Confidential Attachment SC 1.1-H (included as Attachment EB-33-Confidential and Attachment EB-32-Confidential) and can be found in my forthcoming workpapers.

Q. How did you treat these periods when both Cayuga units were offered as Must Run?

A. When both Cayuga units were designated as Must Run, I was unable to directly attribute a single unit's costs and revenues to the steam customer. Moreover, as I described, DEI likely would have committed both units as Must Run even without the steam contract because DEI commits its units as Must Run when it predicts they are economic to run or due to other rare circumstances (e.g. safety, testing, etc.). As such, I excluded these periods when calculating the economic losses that are attributable to the steam contract during the FAC 123 period. Thus, the resulting economic loss attributable to the steam customer equals -$1,442,490 (that is, -$1,165,805 for periods with a single Must Run unit less $276,685 from periods with two Must Run units). This represents the amount that DEI's electric customers will be subsidizing DEI's steam customer for the FAC 123 period as proposed in DEI's application.

Q. Why did you omit the net revenues from the periods when both units were committed as Must Run?

A. When both Cayuga units are offered as Must Run, it creates a unique circumstance in which it is no longer likely that either unit was online strictly to serve the steam customer. For example, when each unit earned over $1 million from September 16-20, 2019, their positive net revenues would have prompted DEI to commit them as Must Run regardless of its obligation to International Paper.

If a Cayuga unit is running because it needs to provide steam to International Paper when self-committing in MISO is otherwise not economic, any gains or losses are attributable to the steam contract. However, if DEI does in fact expect to make money on commitment, whether or not they need the unit for steam is irrelevant in the market context, and they are thus not attributable to the steam contract.

Q. Why did Cayuga Unit 1 lose money when Cayuga Unit 2 was expected to be “significantly in the money” in mid-November of 2019?

A. As previously mentioned, Cayuga Unit 1 lost an alarming $3.2 million in production costs and market charges in a single day on November 13, 2019, when it ramped offline due to an unplanned boiler leak.[65]

Q. Have the losses from the November 13, 2019 unplanned outage at Cayuga been included as part of the retail customer impacts of DEI’s steam contract?

A. No. As discussed above, my calculation of electric market losses due to the steam customer include only the hours when one Cayuga unit was designated as Must Run. Both Cayuga units were offered with a Must Run commitment status on November 13, 2019, due to expected market gains and, therefore, the massive loss from the unplanned outage is not included in my calculation of retail customer losses. Thus, this technical outage plays no part in the total $1,442,490 retail customer loss due to Duke’s steam contract with one steam customer.

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Q. Does Duke quantify or address the significant losses in the energy market incurred from running a Cayuga steam unit to supply the steam customer?

A. No. Duke acknowledges that it has not studied whether the revenues from the steam

[65] Petitioner’s Ex. 1 (Swez Direct), p. 24.

contract are sufficient to offset the MISO market losses from uneconomic operation of the Cayuga unit used to provide the steam.[66]

Q. Does DEI assert that anything could make up for these significant losses being passed to retail customers?

A. Yes. DEI asserts that retail customers benefit from the steam contract in various ways including: demand revenues for steam supply are passed to electric customers, the "fixed cost contribution from International Paper which reduces overall recovery from retail electric consumers,"[67] and the jobs and diversified DEI portfolio enabled by the steam contract.

Q. Are these benefits significant compared to the retail losses?

A. No. DEI touts that steam demand revenues were voluntarily shared with retail electric customers; however, the sharing mechanism effectively accounts for the fact that the steam customer has long underpaid the demand costs associated with steam service.[68] Indeed, once the allocation of demand costs is rectified in the pending base rate case, the cost sharing mechanism will discontinue.[69] Thus, while the sharing mechanism improved an allocation imbalance caused by the time between infrequent DEI rate cases, the

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[66] Duke Response to CAC Data Request 2.27 (included as Attachment EB-2).
[67] Petitioner's Ex. 3 (Diaz Direct), p. 13.
[68] Witness Birnbaum testified in Cause No. 44087 that [redacted]." *See* Confidential Attachment CAC 2.17-A, p.17 (included as Attachment EB-9-Confidential).
[69] DEI Witness Diaz confirms that, "as a result of the conclusion of the pending base rate case, updated costs assigned to steam supply for the test period are removed from the setting of base rates for retail electric customers such that the retail customers will benefit from the allocation of steam supply costs." Duke's Response to CAC Data Request 4.38 (included as Attachment EB-2).

$50,000 voluntary contribution every FAC period[70] does not offer retail electric customers a significant additional benefit when compared to the far greater amount of energy-related economic losses that are likely in the millions each FAC period.

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Furthermore, the steam customer's fixed cost contribution, which is described in DEI's direct testimony,[71] should not be construed as an incremental benefit to retail customers because it simply reflects cost causation. International Paper covers its demand-related fixed cost responsibility by paying for the amount of capacity that it uses when it extracts steam from the Cayuga station. That steam and its electrical capacity are therefore precluded from retail customer use and the fixed costs for providing that capacity should certainly not be borne by retail customers. Thus, this is not an additional benefit to electric customers in excess of what the steam customer should already be paying based on the principles of cost causation.

With regard to the claimed customer benefits from job creation and DEI's diversified sales portfolio, these are unquantifiable in the context of the FAC and thus do not offset the $1.4 million in fuel related costs of the steam contract to retail customers.

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[70] Petitioner's Ex. 3 (Diaz Direct), p. 11.
[71] Petitioner's Ex. 3 (Diaz Direct), p. 8.

3) Recommended Change to FAC Cost Allocation

Q. How do you recommend rectifying the ratepayer burden caused by the steam contract?

A. I recommend that the $1,442,490 in losses be removed from the FAC 123 collection from retail electric customers. Instead of collecting these costs from electric customers, DEI or the steam customer should be held responsible for the losses resulting from their contractual agreement. These losses represent the true cost of the arrangement, for which DEI and the steam customer are responsible.

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Q. Why shouldn't electric customers have to pay the production costs for Cayuga units that do not exceed market revenues?

A. The Cayuga station would not have been producing in the energy market during the single-unit Must Run hours, had it not been contracted to provide an entirely different commodity to an external customer. Duke and International Paper are currently indifferent to the financial losses incurred in the energy market by their agreement because ratepayers indemnify them from the costs through the FAC.

coal at such locations by the end of the FAC period.[93] I would note that, while these measures decreased the amount of coal onsite at Duke's plants, they did not decrease the overall amount that Duke is obligated to purchase.

Q. Did DEI contract during the FAC 123 period to purchase additional amounts of coal, despite its growing oversupply?

A. As part of negotiating the above-mentioned deferral, DEI contracted to purchase an additional 1 million tons of coal – 500,000 tons in each of 2020 and 2021.[94] In addition, in September 2019, DEI issued an RFP for additional coal purchases, which led the Company to verbally commit in late 2019 to purchase an additional 500,000 tons of coal in 2020.[95]

Q. Did DEI say why it issued an RFP for additional coal purchases and committed to purchasing and additional 500,000 tons of coal in 2020?

A. Yes, when asked why Duke proceeded with contracting for an additional 500,000 tons of coal in late 2019 despite declining coal burns and projected oversupply of coal in 2020, Duke Witness Phipps noted that the coal companies at issue were "financially struggling."[96] When asked about this statement, Mr. Phipps testified that it was a matter

[93] Cause No. 38707 FAC 123, Petitioner's Exhibit 4 (Direct Testimony of Brett Phipps), p. 8, lines 10-12. These two offsite storage locations are both located at the mines of one of DEI's coal suppliers. Tr. F-77, lines 5-7; Conf. Response to CAC Data Request 1.5, Confidential Attachments 1.5-A and 1.5-B (Attachments EB-3-Confidential, EB-6-Confidential).

[94] Cause No. 38707 FAC 123, Duke Response to CAC Data Request 1.6(d) (included as Attachment EB-2); Confidential Response 1.3 and related Attachment 1.3-A (included as Attachment EB-Confidential) (contract for deferment).

[95] Cause No. 38707 FAC 123, Duke Response to CAC Data Request 1.8(a), (c) (included as Attachment EB-2).

[96] Cause 45253, Hearing Tr. F-51, lines 1–15.

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VII. Recommendations

A. Edwardsport Disallowance

Q. Do you believe DEI customers should be required to pay for economic losses resulting from imprudent operating decisions made by DEI?

A. No. In particular, DEI ratepayers should not bear the costs of operating Edwardsport where economic losses resulted from imprudent operating decisions as I have described throughout my testimony.

Q. What remedy do you think is appropriate to make customers whole for DEI's imprudent operating choices at Edwardsport?

A. It would be appropriate to reduce the total FAC charged to customers by an amount corresponding to the economic losses that DEI incurred at the plant but which could have reasonably been avoided if the plant were not operated as a Must Run unit on coal. As explained earlier in my testimony, this loss amounts to $4.9 million for the FAC 123 period. Furthermore, it would be appropriate to further reduce the FAC charged to customers by the amount of economic benefit that was foregone by not operating the plant on natural gas. As explained earlier in my testimony, DEI estimated this foregone economic benefit to be approximately $3.0 million for the FAC 123 period. Adding these two components, I recommend a total reduction in FAC 123 charges of $7.9 million associated with Edwardsport.

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B. Cayuga steam customer cost allocation for must run status for steam when the Daily P&L is negative

Q. What recommendations do you have regarding the Cayuga steam issue?

A. As outlined earlier in my testimony, I recommend that any economic losses from electricity generation that resulted from the need to commit a Cayuga unit as Must Run to serve DEI's steam customer should not be allocated to all retail electricity customers. Instead, these losses should be reallocated to either DEI or the steam customer. For the FAC 123 period this amounts to $1,442,490.

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Q. Could the contract between DEI and the steam customer be amended to reflect this?

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A. Yes.

C. Commission guidance on DEI operations on going forward

Q. In addition to these remedies for the FAC 123 period, do you have other recommendations on guidance the Commission should provide for future FAC periods?

A. Yes. There are several areas where I think Commission guidance is warranted and would help to ensure utility operating decisions minimize costs for customers. I have described each of these below.

1) <u>Unit commitment decision reporting requirements and FAC adjustments</u>

For each FAC application, DEI should be required to provide a report that includes the following for each generating unit:

- Hourly unit commitment designation (i.e. Must Run, Economic, Unavailable)