OFFICIAL EXHIBITS

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3 AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	)	**CAUSE NO. 38707-FAC124**

IURC PETITIONER'S EXHIBIT NO. 11 6-17-20 AT DATE REPORTER

SUBMISSION OF DUKE ENERGY INDIANA, LLC'S RESPONSE TO THE COMMISSION'S JUNE 12, 2020 DOCKET ENTRY

Duke Energy Indiana, LLC ("Duke Energy Indiana"), by counsel, hereby respectfully submits its responses to the Commission's docket entry dated June 12, 2020, in the above-captioned Cause. Such docket entry questions and Duke Energy Indiana's responses are as follows. The confidential information redacted within this response and Confidential Attachment 1 are being submitted to the Commission, under seal, pursuant to the Commission's Order dated June 8, 2020.

1. **On pages 4-5 of Mr. Swez's direct testimony, he discusses how DEI determines a unit's commitment status. Among the considerations presented, he mentions the decision is "risk adjusted" and that the company considers the "ability to hedge" purchased energy price exposure. Please provide any quantified values or metrics used by the Company in these considerations.**

Response:

Risk Adjusted Commitment:

In the Company's Daily Profit & Loss Analysis, the model that produces a forecasted daily energy margin from operation of a unit, there is no specific dollar amount included in the analysis to risk adjust the daily margin shown. However, the risk adjustment is applied in the interpretation of the model results. There is no one single risk adjustment value, thus the amount of risk adjustment varies depending on the magnitude of the financial risk involved with the cycling of the unit and the magnitude of the financial gain from cycling the unit. However, in typical situations, it can be appropriate to accept an additional financial risk of between $10,000 to $20,000 for a weekend net financial loss before decommitting a unit. In addition to the fact that things don't always go as planned, there is additional value from having the generator on-line, since the unit can move up from its minimum loading in the event that prices come in higher than planned. (This embedded option value of a generating unit is valuable to customers). Further, this amount changes depending on the situation, thus, "the more customers have at risk by cycling something off, the more risk customers should be reasonably willing to accept by not cycling the unit off-line". It should be noted that the factors that are quantifiable, such as the impact of cycling a Gibson unit to other units that are required to supply steam for startup/shutdown or the startup time and margin losses associated with the energy produced from a unit during startup, are quantified and included in the analysis, and therefore are not included in this risk adjustment discussion.

Ability to Hedge:

To hedge against purchase power price volatility, if the difference between forecasted generation and forecasted demand (the position) warrants, the Company enters into forward power purchase contracts that are financially settled on a specific future date at MISO Indiana Hub. When entering into these transactions, Duke Energy Indiana evaluates the difference between the purchase price for the forward power purchase contract against the expected cost of operating the incremental Company generation unit(s) needed to meet the forecasted load. For example, during the FAC 124 period, meeting the forecasted native load during a typical week with Company-owned generation would require the Company to operate coal-fired generators at a cost of \$28/MWH, but the Company could purchase a forward power purchase contract at a cost of \$26/MWH. In this situation, Duke Energy Indiana would make that purchase, typically in 50 MW increments at a time, essentially fixing a price for purchased power at a cost lower than the expected cost of operating our own generation. However, as the Company engages in these purchase transactions, the market moves to an equilibrium between buyers and willing sellers, and the amount of energy available for purchase at the same price decreases. Eventually additional purchases can only be made at a higher price to the point where the purchases approach to the cost of the avoided generating unit. This is especially true due to the typical size of a unit, since to displace, or "buy off" a 600 MW generating unit takes approximately 12 contracts of 50 MW each. During FAC 124, the Company purchased approximately 50% of its energy from other generators in MISO, an average of approximately 2,000 MW in every hour. It is typically not possible to hedge this amount of energy on a forward basis without significantly affecting the price. It is possible, as the Company does, to purchase a portion of this energy at reasonable, representative market prices for a forward period up until either the volume is not present, the price moves up, or both. Liquidity is a market term indicating the ability to buy or sell an asset without significantly impacting its price. In this instance the asset is a daily, weekly, or monthly power futures contract. Typically, the platform the Company uses to engage in hedging activity, the Intercontinental Exchange (ICE) has approximately 200 to 300 MW daily liquidity at Indiana Hub. Further, note that since there can be inaccuracies in the expected future market price, keeping a generator on-line when its cost is equal to the market cost, all other things being equal, can provide a better hedge than a forward purchase since the generating unit can respond to higher prices by moving up in output from its minimum loading in the event that the expected market price is higher than forecast. This ability to provide additional generation that a financial hedge cannot provide is one additional reason why it may appear that the Company tends to decommit slightly less generation than theoretically expected based purely on the market price comparison against a generator's cost.

As a real example of forward market liquidity and how it relates to the Company's ability to hedge the customers' exposure to purchase power, consider the week of January 27-31, 2020. During the week of January 20-24, as planning for the week of January 27-31 matured, weather forecasts materialized, and it became apparent that this week would be mild with temperatures averaging 4-5 degrees above normal in central Indiana. At the time, the Company had one Gibson unit off-line for reserve shutdown (Gibson 3) and the other four Gibson units on-line, but saw the potential to decommit three additional units for the following week (one unit must remain on during

Winter). During the week of January 20-24, Duke Energy Indiana purchased the following financial swaps at Indiana Hub in preparation and to allow as many units to be decommitted as possible without exposing the Customer to excessive price risk.

Date of Purchase	Trade Price	Start Date	End Date	Amount (MW)	Days
01/21/2020	[redacted]	01/27/2020	01/31/2020	50	Monday-Friday
01/21/2020	[redacted]	01/27/2020	01/31/2020	50	Monday-Friday
01/21/2020	[redacted]	01/27/2020	01/31/2020	100	Monday-Friday
01/21/2020	[redacted]	01/27/2020	01/31/2020	50	Monday-Friday
01/23/2020	[redacted]	01/27/2020	01/31/2020	50	Monday-Friday
01/24/2020	[redacted]	01/28/2020	01/31/2020	50	Tuesday-Friday
01/27/2020	[redacted]	01/28/2020	01/28/2020	50	Tuesday only
01/27/2020	[redacted]	01/28/2020	01/28/2020	50	Tuesday only

For the Monday (1-27) delivery date, 300 MW in hedges were purchased, 450 MW for Tuesday (1-28), and 350 MW for Wednesday (1-29) through Friday (1-31). However, as the amounts purchased increased, the price paid increased up to [redacted], just shy of the on-peak equivalent cost of a Gibson unit. Thus, eventually the liquidity of the market started to influence the commitment decision for the Gibson units.

Ultimately, during the week of 1-27 to 1-31, two additional Gibson units were placed on reserve shutdown (units 4 and 5), and two Gibson units (units 1 and 2) remained on-line. Since the Company was able to purchase between 300 MW and 450 MW in hedges below the cost of the Gibson units, it felt comfortable allowing an additional two Gibson units to be de-committed, however, the Company decided to not de-commit an additional Gibson unit for reserve shutdown. As noted earlier, a generator on-line with a cost equal to the market price provides additional hedge value as opposed to a purchase, since in the event prices are higher than forecast, the on-line generating unit can simply move up from its minimum loading to a higher output.

Finally, please refer to Confidential Attachment 1, the FAC124 Indiana Power Hedging Audit Confidential Exhibit 3, prepared by Michael Chen for the OUCC FAC124 audit for a complete listing.

2. On pages 27-28 of Mr. Swez's rebuttal testimony, several reasons are listed as to why Edwardsport station is offered as Must-Run that are not directly associated with P&L statements (i.e. cycling, LMP effects, etc.). Please provide quantifiable values or metrics to associate with these various qualitative explanations.

Response:

Following are the reasons listed on pages 27 and 28, along with an approximate quantifiable value or metric included where possible. Note that some of these calculations are considered "back of the envelope" and not the result of production costing models:

1. *Cycling Edwardsport station on and off would likely cause the station's equivalent forced outage rate to increase, causing both a lower capacity value for the MISO capacity auction as well as less energy value in the MISO energy markets.*

While we cannot reasonably predict the magnitude of the potential reliability impact, unitized impacts could be, for example:

- Capacity: Assuming, for example a 1% equivalent forced outage rate (EFOR) increase equates to a 6 MW reduction in capacity, the annual capacity value of which, calculated assuming two different MISO capacity values, could be:
  - At the MISO Zone 6 current market price of $5/MW-Day x 6 MW x 365 days = $10,950/year capacity loss for 1% increase in EFOR
  - 5 year forward capacity markets show an increase to $105/MW-Day in 2026: Capacity impact at a price of $105/MW-Day x 6 MW x 365 days = $229,950/year capacity loss for 1% increase in EFOR

- Energy: Assuming, for example a 1% EFOR increase equates to a 6 MW reduction in energy spread equally around the clock:
  - In a $32/MWh on-peak market (2021 current forward price) with a full load average variable production (non-decremented) cost of [redacted], energy value is ($32/MWh – [redacted]) x 80 hours x 52 weeks x 6 MW = [redacted]/year on-peak energy loss for 1% increase in EFOR
  - In a $24/MWh off-peak market (2021 current forward price) with a full load average variable production (non-decremented) cost of [redacted] (assumes unit dispatches to full load off-peak due to low incremental cost), energy value is ($24/MWh – [redacted]) x 88 hours x 52 weeks x 6 MW = [redacted]/year off-peak energy savings for 1% increase in EFOR
  - Therefore, under these assumptions, there would be a total of [redacted]/year (on-peak + off-peak) energy cost associated with a 1% increase in EFOR
- Other costs: In addition to capacity and energy impacts, the cost of remedying the reliability would be considered. The failed equipment due to cycling would require repair at some cost. If this required an outage, the incremental outage time as well as the unit startup costs and off-line auxiliary power consumption costs would also be incurred. As all such costs and durations are event specific and cannot be reasonably predicted.

2. *The station's gasifiers and other gasification systems have an approximate 14-day cycle time (operating to ambient and then back to operating). Thus, if the gasifiers are brought off-line, the unit would be unavailable on coal for this period.*

- Avoiding a cold startup at Edwardsport saves the cold startup cost of [redacted] (this figure represents the startup fuel cost only, but doesn't include the off-line auxiliary power required to cool the Air Separation Unit (ASU) and operate other gasification systems)
- The syngas unit rating is assumed to be 607 MW, which is the average of the seasonal ratings.
- Operating the unit on natural gas causes, on average, a 120 MW derate with a unit average rating of 487 MW on natural gas, the energy value of which depends on the market at the time and the difference in the units' cost on syngas vs. natural gas:
    - Assuming a $2.50/dth natural gas price (current 2021 market price) equating to a [redacted] unit cost on natural gas, $26/MWh unit cost on syngas, $32/MWh on-peak energy market and $24/MWh off-peak energy market:
        - 607 MW x ($32/MWh - [redacted]) x 80 hours x 2 weeks + 607 MW x ($24/MWh - [redacted]) x 88 hours x 2 week = [redacted] energy loss for 2-week period (cost of loss of syngas unit)
        - 487 MW x ($32/MWh - [redacted]) x 80 hours x 2 weeks + 487 MW x ($24/MWh - [redacted]) x 88 hours x 2 weeks = [redacted] energy savings for 2-week period (value of natural gas unit)
        - Net savings of [redacted] for 2-week period
    - Assuming a $4/dth natural gas price equating to a [redacted] unit cost on natural gas, $26/MWh unit cost on syngas, $39/MWh on-peak energy market, $27/MWh off-peak energy market (assumes energy market moves up with increase in natural gas cost) and unit minimum load of 361 MW on natural gas:

- 607 MW x ($39/MWh - [redacted]) x 80 hours x 2 weeks + 607 MW x ($27/MWh - [redacted]) x 88 hours x 2 week = [redacted] energy loss for 2-week period (cost of loss of syngas unit)
- 487 MW x ($39/MWh - [redacted]) x 80 hours x 2 weeks + 361 MW x ($27/MWh - [redacted]) x 88 hours x 2 weeks = [redacted] energy loss for 2-week period (value of natural gas unit – *i.e.*, because the unit can startup and shutdown more quickly on natural gas fuel, it can react faster to changes in market prices, thus when the unit is out of the money, it normally would not run and this value would therefore be zero)
- Net loss of [redacted] for 2-week period

3. *De-committing Edwardsport gasifiers for long periods of time would cause loss of essential personnel.*

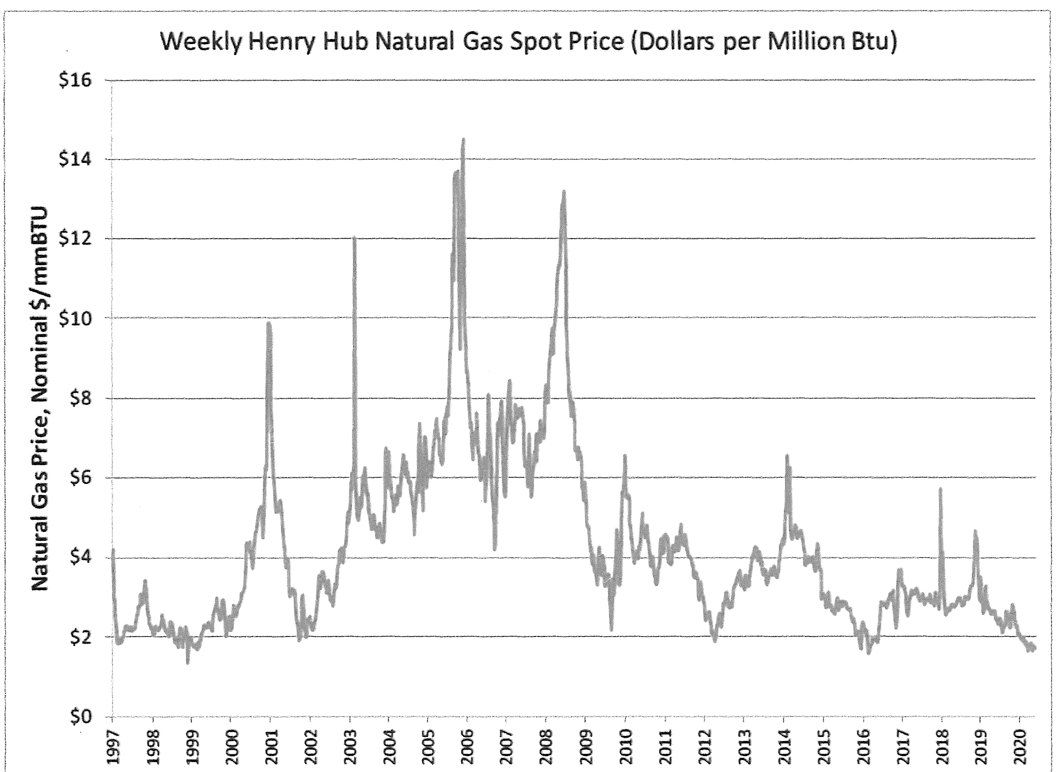
Please note that not included in the analysis below are the potential savings from personnel loss, local economic impact/job losses, loss of tax credits associated with burning coal, impact on coal inventory and contracts, and other potential issues.

- Loss of burning coal would cause a permanent 120 MW loss of capacity and energy:
  - Capacity: The annual capacity value, calculated assuming two different MISO capacity values:
    - At the MISO Zone 6 current market price of $5/MW-Day x 120 MW x 365 days = $219,000/year capacity loss

- 5 year forward capacity markets show an increase to $105/MW-Day in 2026: Capacity impact at a price of $105/MW-Day x 120 MW x 365 days = $4,599,000/year capacity loss

■ Energy:

- Energy market impact from de-commitment of the syngas unit is dependent on multiple factors, including future natural gas price, on-peak and off-peak energy market prices, loss of 120 MW of station capability, and minimum and maximum capability of the natural gas unit among other factors.
- With the volatility in natural gas prices, a simple calculation of this option is not feasible. A chart of the natural gas spot price is shown below that depicts the historical highs and lows of natural gas prices at Henry Hub.



4. *Switching the station to natural gas for short periods of time may often appear to be a better economic decision than it really is. At times, the Daily Profit & Loss Analysis that the Company uses to inform its commitment offer does suggest cycling the station to natural gas for short periods of time. However, this can be an erroneous analysis, since the analysis doesn't include the fact that gasification systems, such as the air separation unit, cannot be turned off for short periods of time if the unit is switched over to natural gas, continuing to consume auxiliary energy and not allowing for the anticipated savings. The Edwardsport natural gas unit on the Company's daily analysis assumes that the gasifiers are totally shut down which for a short shutdown is an inaccurate assumption.*

Ignoring the auxiliary energy consumed by the gasifiers (~150 MW) when theoretically switching over to natural gas for a short period of time essentially eliminates all perceived savings.

- Assuming an energy market of $28/MWh (average of 2021 on-peak and off-peak energy markets) and the unit on natural gas has a cost of [redacted] (assuming $2.50/dth gas), the unit on natural gas is more expensive than the unit on syngas when the auxiliary energy usage is considered, as would be the case from cycling to natural gas over the weekend or any short period of time.
- (540 MW x [redacted] + 150 MW x $28/MWh) / 540 MW = [redacted]
- Note that after accounting for auxiliary power usage, the cost of the unit on natural gas is approximately equal to the cost of the unit on syngas.

5. *Firm natural gas transportation. Currently, the Company has one contract for firm natural gas on Midwestern pipeline, the gas pipeline that serves Edwardsport, Wheatland, and*

Vermillion Stations. The contract, for 52,800 dth/day, is only roughly enough to serve slightly over half of the natural gas needs for Edwardsport Station (Edwardsport would burn 96,000 dth/day assuming an 8,000 Btu/KWh heat rate and 500 MW generation output for each hour of the day). In addition, utilization of Edwardsport solely on natural gas would reduce the ability for this contract to be used for Wheatland and Vermillion stations as well. Although the Company has the ability to buy delivered gas from third party suppliers in addition to transporting on the Midwestern Firm Transport to Wheatland, Edwardsport and Vermillion Stations, if Edwardsport were to switch to 100% natural gas, it would make third party supply scarcer and most likely more expensive when Wheatland and Vermillion also are running.

- This would be dependent on multiple factors, but if the Company decided an additional 50,000 dth of firm transport were required to serve the daily natural gas burn at Edwardsport on natural gas, the cost would be an additional cost of approximately $1,153,380 per year.
- Current cost of monthly gas demand = $1.9223/dth/month x 50,000 dth x 12 months = $1,153,380 annual cost for additional firm transport
- In addition, there would be daily imbalance tolerance and associated charges that were not quantified here.

6. *Natural gas volatility. Although the Company isn't predicting a fundamental return to higher gas prices, external risks to natural gas still exist, and retirement or moth balling of the Edwardsport gasifiers eliminates any option to burn coal in the event that natural gas prices increase. Operating solely on natural gas could essentially become a permanent*

decision, losing the diversity value of coal, and in addition the Company would lose valuable gasification expertise in the interim.

- See the natural gas Henry Hub chart from #3 above, demonstrating wide historical volatility (large changes in short timeframes)[1]. Even as recently as the winter of 2018, gas prices approached $5-$6/mmBTU.

7. *Lastly, as explained by Mr. Gurganus in Duke Energy Indiana's pending rate proceeding, Edwardsport is permitted to operate on coal as a primary fuel and natural gas as a secondary fuel. The permits do not really contemplate operating Edwardsport on natural gas as a primary fuel over extended durations.*

   - See #3 and #4 above.

8. *Operation of Edwardsport solely on natural gas is shortsighted as it only considers the short-term impact as opposed to a long-term viewpoint.*

   - See #3 and #4 above.

[1] https://www.eia.gov/dnav/ng/hist/rngwhhdW.htm

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing electronically to the following:

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ATTACHMENT 1 IS CONFIDENTIAL