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By electronic mail
Indiana Utility Regulatory Commission
ATTN: Research, Policy, and Planning Division
101 W. Washington Street, Suite 1500E
Indianapolis, IN 46204-3407
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RE: Indiana Coal Council Comments on Duke IRP

Dear Dr. Borum,

On behalf of the Indiana Coal Council (ICC), please accept the attached comments on Duke Energy Indiana's (DEI) 2018-19 Integrated Resource Plan (IRP). The ICC greatly appreciates the opportunity afforded by the Commission to submit stakeholder comments as part of the IRP process. The ICC also greatly appreciates the cooperation it has received from DEI throughout the stakeholder process.

Please direct any questions or requests for further information related to the ICC's comments to me at the information above. Should the Commission wish to speak with the ICC's consultants, we would be happy to make them available to you.

All the best,

Jeffery A. Earl

ICC COMMENTS ON DEI IRP

The Indiana Coal Council (ICC) conducted a review of the Integrated Resource Plan (IRP) that Duke Energy Indiana (DEI) prepared and submitted to the Indiana Utility Regulatory Commission (IURC) on July 1, 2019.

CONCLUSIONS AND RECOMMENDATIONS

1. DEI has an appreciation of its coal assets. In 2018, DEI's largest two coal plants, Cayuga and Gibson ranked #1 and #2, respectively, in terms of capacity factor when compared to the other utility-owned coal-fired plants in Indiana.[1] Both Gibson and Cayuga had heat rates, the primary measure of efficiency, well below 11,000 Btu/kwh in 2018, with Cayuga the most efficient utility plant in that year. DEI indicated that it believes, with the exception of Gallagher, its remaining coal plants will continue to operate economically through at least 2021. While DEI has not committed to any retirements except Gallagher, DEI indicates that its primary motivation for a phased retirement of its coal units is not economics. Rather it is a diversification strategy in recognition of the relatively large share of generation provided by coal and the resulting exposure to potential carbon-related costs.

2. DEI's long-term plan suggests that natural gas is generally the lowest-cost replacement for the retiring coal plants. ICC believes that DEI did not give adequate consideration to total carbon emissions from natural gas because its measurements focused only on generation plant annual emissions. The appropriate analysis of a new gas plant is through a life cycle analysis (LCA) of carbon emissions that not only considers emissions from the plant through its expected useful life but also considers upstream emissions, i.e., emissions at the wellhead and during transportation. Significant methane is liberated in the production and transportation of natural gas. Methane is a much more potent greenhouse gas (GHG) than carbon.

3. DEI did not evaluate what role carbon capture can play in its future resource plans. The Edwardsport generating plant was originally designed to employ carbon capture. Even though that element was abandoned prior to the completion of the plant, Duke's IRPs should continually re-evaluate whether the plan for carbon capture should be revived. Further, given the current availability of Section 45Q tax credits and DEI's concerns over its long-term exposure to carbon, it appears timely as well.

4. DEI did not consider strategic alternatives to a phase out of its coal plants during the 20-year forecast period. Such alternatives could include diversification of ownership of the plants (e.g., with other regulated in-state utilities, merchants, and third parties) and retrofit of carbon capture onto the existing plants. Nor did DEI evaluate carbon offset

[1] Warrick 4, which is operated by Alcoa and owned 50/50 with Vectren, is not included in the comparison.

options, which could be lower in cost while achieving the same net reduction in emissions, and which could also address DEI's perceived risk.

5. ICC identified a number of problems with DEI's modeling that could be improved when DEI prepares its next IRP or considers alternative resource plans. For example, DEI acknowledges it did not consider all transmission expenses associated with integration of renewables in the system nor did DEI consider a scenario in which natural gas prices rose significantly and coal prices did not.

6. DEI indicated that its next IRP will reconsider all options. DEI also indicated that it was not limited to the IRP schedule. Should events dictate earlier reconsideration, DEI would proceed to do so. DEI made no mention of the legislation-mandated task force referred to as the 21st Century Energy Development Task Force (Task Force). The Task Force is required to do the following: (1) examine and evaluate specified aspects of the state's policies concerning electric generation portfolios; (2) develop recommendations for the general assembly and the governor concerning any identified challenges with respect to Indiana's electric generation portfolios; and (3) issue a report setting forth the task force's recommendations not later than December 1, 2020. ICC believes it would be appropriate for DEI's next IRP to provide adequate time for consideration of the Task Force's recommendations.

DEI COAL ASSETS

DEI has three coal-fired power plants and one integrated gasification combined-cycle (IGCC) that collectively provide over 90 % of DEI's generation. These plants are equipped with pollution control equipment and are generally compliant with all current and expected regulations, including Effluent Limitation Guidelines (ELG). As shown below, the two largest DEI plants, Cayuga and Gibson, operate at relatively high capacity factors and rank #1 and #2, respectively, in terms of capacity factor among Indiana utility coal-fired plants. The Capacity Factor indicates the actual utilization of the plant.

INDIANA UTILITY COAL-FIRED PLANTS

Operator	Plant	MW	2017 Generation	2017 CF	2018 Generation	2018 CF	Average 2017 and 2018 CF
DEI	Cayuga	985	5,734,487	66%	6,082,109	70%	68%
DEI	Gibson	3,144	17,996,759	65%	17,631,801	64%	65%
IPL	AES Petersburg	1,664	9,341,524	64%	9,101,208	62%	63%
Hoosier	Merom	1,008	4,909,662	56%	5,870,298	66%	61%
Vectren South	F B Culley	360	1,843,436	58%	1,912,244	61%	60%
OVEC	Clifty Creek	1,231	6,037,635	56%	6,369,305	59%	58%
I&M	Rockport	2,600	10,923,442	48%	11,894,109	52%	50%
Vectren South	A.B. Brown	500	1,919,347	44%	2,409,437	55%	49%
NIPSCO	R M Schahfer	1,625	4,948,283	35%	6,755,808	47%	41%
NIPSCO	Michigan City	469	1,280,833	31%	2,040,518	50%	40%
DEI	Edwardsport	630	1,933,355	35%	1,828,443	33%	34%
DEI	R Gallagher	280	194,215	8%	285,152	12%	10%
Total		**14,496**	**67,062,978**	**53%**	**72,180,432**	**57%**	**55%**
DEI		**5,039**	**25,858,816**	**59%**	**25,827,505**	**59%**	**59%**
DEI excluding Gallagher		**4,759**	**25,664,601**	**62%**	**25,542,353**	**61%**	**61%**

Cayuga also led the state's coal-fired power plants in terms of efficiency (heat rate) in 2018. The Gallagher station has the highest (poorest) heat rate reflecting its very low capacity factor. Not surprisingly, the rankings for capacity factor and heat rate are similar which demonstrates how the capacity factor affects plant efficiency. Simply put, the higher the capacity factor, the more efficient the power plant.

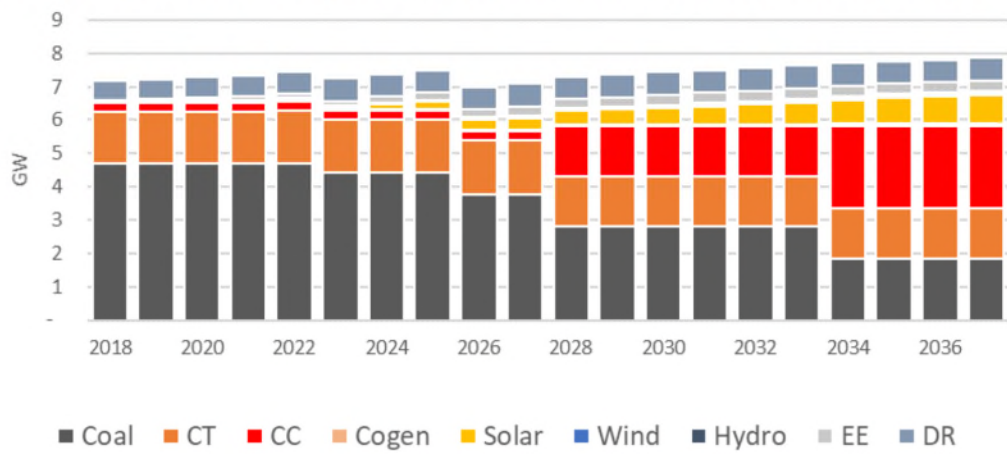
Company	Plant	2018 Elec Fuel Consumption (MMBtu)	2018 Net Generation (MWH)	Calculated 2018 Heat Rate (MMBtu/KWH)
DEI	Cayuga	60,910,976	6,082,242	10,015
I&M	Rockport	120,066,241	11,894,109	10,095
Hoosier	Merom	61,286,582	5,870,298	10,440
IPL	AES Petersburg	96,550,893	9,101,269	10,609
OVEC	Clifty Creek	68,520,782	6,369,305	10,758
DEI	Gibson	189,741,687	17,631,801	10,761
DEI	Edwardsport	42,850,594	3,962,018	10,815
Alcoa	Warrick	47,326,406	4,336,582	10,913
NIPSCO	Michigan City	22,361,452	2,040,518	10,959
Vectren South	F B Culley	20,972,594	1,912,244	10,968
Vectren South	A B Brown	27,137,491	2,444,520	11,101
NIPSCO	R M Schahfer	76,971,291	6,771,610	11,367
DEI	R Gallagher	3,804,474	285,152	13,342

Source: 2018 EIA Form 923

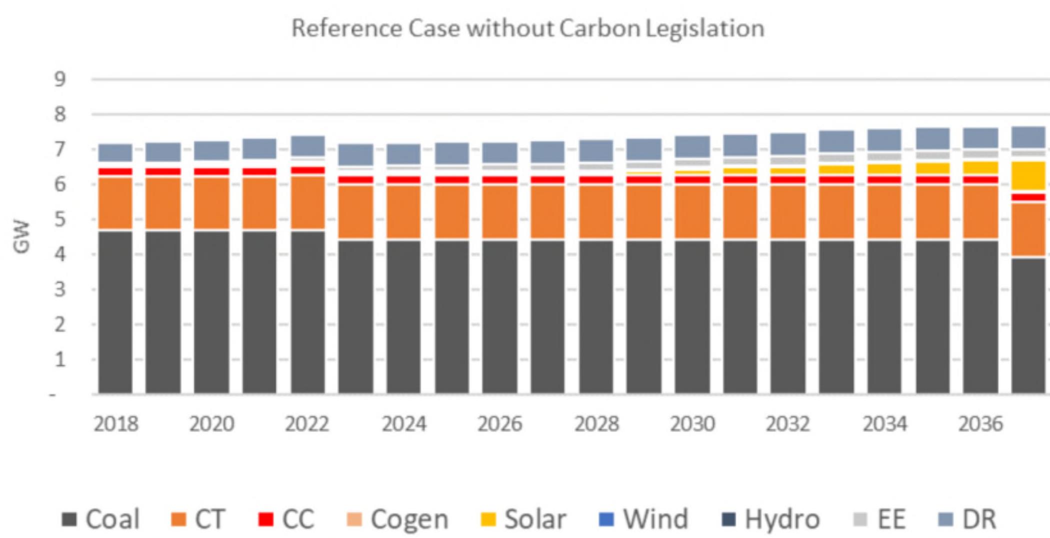
PREFERRED RESOURCE PLAN

DEI's Preferred Resource Plan is the scenario DEI defines as the Moderate Transition Plan. As shown below, the Moderate Transition Plan provides for a modest increase in solar and wind with natural gas combined-cycle (CC) as the primary capacity replacement. DEI also assumes growth in Demand Response.

Figure V.16: Capacity (contribution to peak MW) by year for the Moderate Transition portfolio



DEI assumes a significant carbon cost in the Moderate Transition Plan. As shown below, the resource plan without the assumed carbon cost, is materially different in that the only coal plant retirements found to be economic through 2036 are the two Gallagher units.



As shown below, DEI measured the environmental impact of its scenarios through a metric of annual carbon emissions.

Characteristic	Metric
Cost	5-year PVRR, 20-year PVRR
Risk	Cost Variability Across Scenarios & Sensitivities
Flexible	Frequency, Size, Timing of Irreversible Decisions
Environmental Impact	Annual CO2 Emissions
Reliable	Meets Long-Term Planning Reserve Margin Each Year

DEI stated it wanted a single metric for the environment and it chose annual CO_2 emissions because, according to DEI, "annual CO_2 emissions correlated with other environmental emissions, such as SO_2 and NO_x." This is actually not the case. Emissions from natural gas (uncontrolled) per AP-42[2], the industry standard, are shown below. SO_2 emissions from natural gas are negligible; CO_2 emissions from natural gas are substantial.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 scf] = (3.67)(CON)(C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

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[2] https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf (last visited on 12/5/19). The Emission Factor Rating reflects the quality of the emission factor calculation.

In determining the contribution of a CC plant to GHG emissions, both the upstream and downstream emissions are relevant. The upstream emissions include the production of natural gas and transportation through its distribution to the consumer. The downstream emissions include the operation of the power plant and the transmission and distribution of electricity to the consumer. The sum of these emissions over the forecasted useful life of the plant compose the life cycle emissions for the plant.

In recent years, LCA has become the norm for emissions analysis. The National Energy Technology Laboratory (NETL) which is part of the U.S. Department of Energy (DOE) national laboratory system, performs and sponsors a range of energy and environmental research and development.[3] NETL alone lists over 100 publications related to its work in LCA on its website, a number of which focus on the LCA of new natural gas plants. In a 2016 report, NETL explains its adoption of LCA analysis as follows:

> In recent years, the National Energy Technology Laboratory (NETL) has been using life cycle analysis (LCA) as a new and innovative way to analyze and compare different power production and transportation fuel production pathways. By using LCA, NETL has integrated a holistic approach to comparing energy production pathways instead of solely considering combustion emissions at energy conversion facilities (i.e., power plant or fuels refinery).[4]

LCA is important for at least two reasons. First, carbon has a relatively long residence time in the atmosphere. This means, among other things, the amount of carbon emissions over the useful life of a new generating plant must be considered particularly in relation to the alternatives. An existing coal plant that operates for 10 additional years and is then replaced with renewables could have lower total carbon emissions than a new CCGT that operates for 40 years or more.[5]

Second, significant methane is liberated in the production and transportation of natural gas. Methane is a much more potent GHG than carbon. Standard analyses convert the methane to a carbon dioxide equivalent (CO_2e) when estimating life cycle carbon emissions. According to the U.S. Environmental Protection Agency (EPA), if one assumes a 100-year global warming potential (GWP) of 1 for CO_2, than methane is estimated to have a 100-year GWP of 28-36, and a 20-year GWP of 84-87.[6] Further, because methane has a shorter lifetime than CO_2, but then degrades to CO_2 in the atmosphere. Thus, the emission of methane, e.g. during the production of

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[3] https://www.netl.doe.gov (last visited 12/5/19).

[4] *Upstream Dashboard Tool Documentation*, NETL, August 16, 2016, p. 1, available at https://www.osti.gov/servlets/purl/1433926 (last visited on 12/5/19).

[5] And if the CCGT plant only operates for 15 years (less than half of the typical useful life of a CCGT) and is then replaced with renewables, its total costs to customers would be substantially higher than transitioning an existing coal plant to renewables at the end of the coal plant's useful life.

[6] Understanding Global Warming Potentials, available at http://www.epa.gov/ghgemissions/understanding-global-warming-potentials (last visited 12/5/19).

natural gas, has a large, initial 20-year impact (GWP of 84-87) followed by an additional 80-year impact of the remaining CO_2.

It is thus disingenuous to analyze strategies to reduce carbon emissions without including an LCA of the GHG emissions associated a fuel-type, including production- and transportation-related emissions. Most Indiana utilities have argued in their IRPs that their obligations related to carbon are only related to generation or "inside the fence." That may or may not be the case because the regulatory construct for the hypothetical carbon regime does not exist. Any aggressive carbon/GHG reduction program is likely to include all emission sources, from production through transportation to generation. Even if the price of carbon associated with production and transportation is not directly assessed to the utility, it would certainly be assessed to the producer and transporter, who would pass those costs on to the utility through in the price of gas. Therefore, future IRP analyses should incorporate LCA when considering the level of carbon emissions, especially in scenarios that assume a carbon cost.

CARBON CAPTURE

The initial plan for the Edwardsport IGCC included carbon capture. A variety of reasons led to the abandonment of the carbon capture component of the plant. Since that time, there have been significant advances in carbon capture technology and incentives that raise the question of whether the time has come for DEI to reconsider carbon capture at Edwardsport.

For example, Section 45Q of the U.S. tax code provides a performance-based tax credit for carbon projects that can be claimed when an eligible project base has:

a. Securely stored the captured CO_2 in geologic formation, or

b. Beneficially used captured CO_2 or its precursor CO as a feedstock to produce fuels, chemicals, and products such as concrete in a way that results in emission reductions as defined by federal requirements.

Section 45Q tax credits are intended to encourage private investment of the deployment of either Carbon Capture and Sequestration (CCS) or Carbon Capture Utilization and Storage (CCUS). There is considerable interest in the tax credit currently from power plants and other types of projects. It is likely that a continuation of Section 45Q tax credits or their equivalents will be available under any carbon regime.

In 2017, NRG started the Petra Nova plant, which is a commercial-scale, post-combustion, carbon capture technology added to the existing coal-fired W.A. Parish Generating Station. Petra Nova, which is now a 50/50 joint venture between NRG Energy and JX Nippon Oil & Gas Exploration, is designed to capture 90% of the CO_2 emissions. The captured CO_2 is compressed and transported through an 80-mile pipeline to an operating oil field where it will be utilized for enhanced oil recovery and ultimately sequestered. There is also significant global momentum and policy support to drive CCS and CCUS. This is in recognition that at current global coal consumption levels of over eight billion tonnes, it will be challenging without carbon capture technology to reduce in a meaningful way emissions of carbon into the atmosphere. DEI should consider a retrofit of carbon capture technology on Edwardsport or any of the remaining coals plants as an option in its future resource plans.

STRATEGIC ALTERNATIVES

DEI indicated that its retirement plans for Gibson and Cayuga are driven by its high reliance on coal and future concerns about a carbon regime. As shown above, neither the Gibson nor Cayuga plant retirements are economic absent a carbon regime.

With respect to its high reliance on coal, DEI did not appear to consider strategic alternatives to a phase out of its coal plants during the 20-year forecast period. One alternative could include diversification of ownership of the plants, potentially with other regulated in-state utilities, merchant generators, and/or large industrial customers.

As noted above, DEI also did not consider retrofitting carbon capture technology on any of its units. Carbon capture would eliminate 90% of carbon emissions, thereby eliminating the perceived carbon-cost risk with continued reliance on coal. DEI also did not appear to investigate its ability to acquire carbon offsets, which could provide a more cost-effective way to negate the need for carbon emission reductions at its plants.

DEI should consider alternative risk mitigation strategies if that risk is driving its decision to reduce otherwise economic coal generation.

MODELING CONCERNS

DEI developed five scenarios for its IRP analysis. The key assumptions in each scenario are provided below.

Table IV.1: Scenario Assumption Summary

Scenario	Gas Price	Coal Price	Load Forecast	Carbon Price	Cost of Solar & Wind	Cost of EE	PTC & ITC
1) Slower Innovation	High	High	Low	None	High	High	Renewed
2) Reference Case	Mid	Mid	Mid	Mid	Mid	Mid	Expire
3) High Tech Future	Low	Low	High	High	Low	Low	Expire
4) Current Conditions	Market	Market	Mid	None	Mid	Mid	Expire
5) Reference Case, No Carbon	Mid	Mid	Mid	None	Mid	Mid	Expire

DEI included gas and coal prices among the key assumptions. In all scenarios, gas and coal prices are correlated (i.e., high gas—high coal). While there may be periods of correlations, historically gas and coal prices have not been correlated.

Further, there is general industry consensus that gas prices are at historical lows. This is due largely to the recent prevalence of natural gas obtained through hydraulic fracturing or "fracking." There is less consensus regarding the outlook for natural gas prices. Given that the power sector is only one-third of the market for natural gas, future gas prices may be increasingly driven by the price for natural gas in other market segments. In addition, any state or federal legislation or regulation that substantially curtails or eliminates fracking could result in a sudden and dramatic decrease in the supply and corresponding dramatic increase in the price of natural gas. As a result, it would be appropriate in its next IRP for DEI to include at least one scenario in which gas prices are high relative to coal prices.

Another area of concern is the cost of integration of renewables into the DEI system. DEI indicated that it did not fully evaluate such costs. These costs can turn out to be higher than estimated in the IRPs. In July 2019, Ameren Missouri announced it had cancelled development of a 157 MW wind farm in Missouri because "significant upgrades would have been required on the transmission system to accommodate the project, leading to higher costs."[7] Further, in 2010 MISO reclassified wind as a dispatchable intermittent resource (DIR) and recently announced it was considering the same classification for solar. As a DIR, wind became dispatchable, thereby changing the economics associated with wind generation. MISO also recently culled about 3.5 GW of renewable projects based on the need for expensive and lengthy transmission system upgrades.[8] In future resource plans, it would be appropriate for DEI to quantify and reflect such costs in the evaluation of renewable resources.

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[7] https://seekingalpha.com/news/3482867-ameren-edf-cancel-missouri-wind-project-due-high-costs (last visited 12/5/19).

[8] https://pv-magazine-usa.com/2019/11/13/miso-is-out-of-room-for-solar/ (last visited on 12/5/19).