RELIABLE ENERGY'S COMMENTS ON DUKE ENERGY INDIANA'S 2021 INTEGRATED RESOURCE PLAN

May 16, 2022

I. INTRODUCTION AND SUMMARY

Reliable Energy participated in the stakeholder process and conducted a review of the Integrated Resource Plan (IRP) that Duke Energy Indiana (DEI) submitted to the Indiana Utility Regulatory Commission (IURC or Commission) on December 15, 2021. Reliable Energy is a trade association formed in 2020 by representatives of Alliance Coal and Hallador Energy. Reliable Energy understands the changing energy landscape, and works with numerous industry partners and association members to advocate for reliable and affordable energy prices, as well as clean coal technologies that can power Indiana's economy.

Reliable Energy appreciates the opportunity to participate in the informal stakeholder process and commends DEI on its attempts to be inclusive and welcoming to all stakeholders. The comments provided below reflect on the issues related to flaws in process as well as some specific concerns related to DEI's analysis.

Before addressing these substantive concerns, it is important to note that that changes to DEI's 2021 IRP appear to be primarily driven by its parent company's announcement of its intent to be off coal by 2035. These types of statements from DEI and other electric utilities are effectively "greenwashing" their brands, because all of them seem to acknowledge, although perhaps not directly in their IRPs, that significant technological advancement is necessary in order to meet their targets. The unrealistic IRPs which result from these aggressive environmental goals could have a significant adverse effect on the cost of electricity and the state of Indiana —a fact with which a utility with a guaranteed return on investment has very little concern. Just this week, the California Air Resources Board (CARB) rejected Governor Gavin Newsom's proposal to accelerate the state's 2045 carbon neutrality goal by a decade, finding it is too costly.[1] Liane Randolph, CARB chair, said:

> "The modeling shows that the ambitious target towards 2035 does result in some significant costs that will have significant economic impacts…When you're trying to transition away from fossil fuels, you need to replace that activity with something else…The 2045 target allows us to fold in those costs over time."[2]

Reliable Energy recognizes the energy industry is in transition, and urges the Commission to consider the same broad impacts CARB did—not simply accept pressure from utilities and their

[1] https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp.pdf?utm_medium=email&utm_source=govdelivery

[2] https://subscriber.politicopro.com/article/eenews/2022/05/11/calif-rejects-plan-to-aim-for-2035-carbon-neutrality-00031620

shareholders to decarbonize the grid at the expense of grid reliability and resilience and the customers' pocketbook.

The primary flaws in the IRP process are threefold. First, the IRP process itself has gotten out of control. Millions of dollars and often years are spent by the stakeholders and the utilities in advocating and analyzing scenarios many of which become irrelevant as a result in changes in markets, technologies, the economy, and regulatory obligations by the time the IRP is issued. Second, the Commission does not actively participate in the development of the IRP. While the Director writes a report, the final report is often issued after a filing for a Certificate of Public Convenience and Necessity (CPCN) reliant on the IRP has been filed.[3] Even if the Director finds flaws in the IRP process or results, it is often too late for the IURC to consider when addressing the CPCN. Further, the lack of formal IRP proceedings before the Commission limits the Commission's engagement. Third, each utility is not tasked to consider how its plans are affected by the collective activity of the other utilities in the state or in the relevant RTO.

Reliable Energy and its predecessor have witnessed how the flaws in this process have and, left unchanged, will continue to produce higher power rates because of growing stranded costs, over commitment by utilities to long-term power purchase agreements without Commission oversight, and exposure to reduced utility reliability and resilience. Indiana residential consumers have already seen significant bill increases in the last ten years:[4]

Jurisdictional Electric Utility Residential Customer Bills ($/1000 Kwh)

	2012	2021	$ Change	% Change
AEP (I&M)	$ 85.41	$150.53	$ 65.11	76%
NIPSCO	$115.17	$157.01	$ 41.84	36%
AES Indiana	$ 94.73	$116.92	$ 22.20	23%
Duke Energy Indiana	$105.38	$129.45	$ 24.07	23%
CenterPoint Indiana	$149.28	$ 163.20	$ 13.92	9%

The broken IRP process is the starting point for a continued rise in electricity prices in Indiana. A significant manifestation of these failures will become apparent in the 2022/2023 MISO planning year due to the results of the Planning Resource Auction (PRA). On April 14, 2022, MISO announced the capacity auction results for 2022/2023. Capacity prices in Zone 6 (Indiana) increased from $5/MW-Day to almost $240/MW-Day, almost a 50-fold increase. Reliable Energy and its members have long been raising concerns about this expected capacity shortage, which is due to the mismatch between retirements of dispatchable resources and additions of intermittent resources, leading to MISO using the Cost of New Entry (CONE) as the basis for the capacity price in seven of the MISO zones. The Commission should recognize that

[3] Reliable Energy expects that DEI will file for CPCN's for both renewable projects as well as the proposed CCGT's before the Director's Report is finalized.

[4] Source: Table 7 of the 2021 IURC Residential Bill Survey: https://www.in.gov/iurc/files/2021_Residential-Bill-Survey.pdf

this significant capacity cost increase in MISO, is in part a result of the fact that the Commission fails to evaluate the impact of individual CPCN case on the State and the market as a whole.

While this increase in capacity costs will affect all ratepayers, it will hurt the ratepayers most in service territories in which the utility has a capacity shortfall. MISO issued a further cause for concern by stating that "unless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year's auction will continue."[5] The temporary retention of existing capacity offsets the need for additions.

If DEI chooses to execute the Preferred Portfolio, DEI could have a significant mismatch in capacity. If Gibson Generating Station's Unit 5 (Gibson 5) is retired in 2025 and both Cayuga Station Units 1 and 2 (Cayuga) are retired in 2027, and as discussed in more detail below, Duke's plan to build new gas fueled generation in 2027 suffers regulatory delays, Duke will be forced to rely on market purchases. There is little information in the IRP about natural gas price forecasts, even though the Preferred Portfolio assumes installation of approximately 2400 MWs of new natural gas.[6] The results of the recent MISO auction should require a reconsideration of the timing and extent of the coal plant retirements. Capacity shortages in Zone 6 and adjacent zones have and will continue to cause the higher capacity prices. This affects not only ratepayers, but also the reliability and resilience of the grid as a whole.

While DEI was well intentioned in this IRP, its Preferred Portfolio is unfortunately a prime example as to why changes are needed in the IRP process, including increased Commission engagement. As discussed below, the process has become too mechanical and less strategic as the utilities spend enormous resources in modeling and stakeholder involvement and little time in considering ratepayer impacts, how best to ensure system reliability, and how the resource decisions of other utilities in Indiana and nearby states could be relevant to their choices.

Finally, while Volume 1 of the IRP is well written document, it is lacking in much of the detail necessary (even when considering Volume 2) that is appropriate for inclusion in an IRP. For example, the report uses installed capacity (ICAP) in its Volume 1 discussion, despite the fact that DEI recognizes that Unforced Capacity (UCAP) is what is actually used to measure DEI's compliance with MISO's resource requirements. Despite its ICAP based discussion of its capacity mix in Volume 1, DEI then switches in Volume 2 to a discussion of it is modeling on a UCAP basis.[7] ICAP represents physical generating capacity adjusted for ambient weather conditions, while UCAP represents the percentage of ICAP available after a unit's average forced outage rate is taken into account. MISO uses UCAP because it is a far more accurate indicator of what capacity will actually be available from a generating unit.

[5] https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf

[6] DEI did provide its assumption only following a direct query.

[7] In a recent meeting with MISO, participants were informed that MISO is considering reducing the UCAP for wind and solar because such resources are not achieving the current assumptions. Any reduction in UCAP for renewables would serve to increase their costs as more additions would be needed to satisfy reserve requirements.

These comments are organized as follows:

II. Process and Evidential Issues;
III. The DEI IRP; and
IV. Problems with DEI's Preferred Portfolio.

II. PROCESS AND EVIDENTIARY ISSUES

The current informal stakeholder process, used in lieu of a formal Commission proceeding, allows utilities to control the flow of information, impose their own biases on the preferred outcome of the IRP process, and results in the elimination or demotion of otherwise reasonable and economic portfolio alternatives.

One example of this is the flexibility afforded each utility in developing the metrics they will apply to determine which of the options considered should be deemed the Preferred Portfolio. As a result, there is limited consistency across utilities over which metrics are used and how those metrics are determined. Reliable Energy believes the Commission should establish the minimum required metrics that all utilities must provide. Required metrics should include:

- True affordability as determined through a ratepayer impact analysis by customer class over the first 10 years of the proposed resource's economic life;
- Net Present Value (NPV) of Revenue Requirements, including sunk and base rate costs by year with summarized values for 10 and 20 years to get a more accurate sense of customer costs;
- Life Cycle Analysis of Carbon Emissions, including Upstream Emissions, to obtain a precise assessment of what is truly "net zero";
- Capacity and energy diversification by source and type by year to assess, reliability and resilience;
- Percent of energy and capacity forecast to be purchased under PPAs in each year to determine market risk and potential price volatility;
- Stranded capital costs due to resource retirements that will later be sought for rate recovery by year under each scenario; and
- Costs in base rates associated with each proposed resource retirement.

These metrics provide useful information to the Commission that is often overlooked. For example, recovery of stranded costs can significantly impacts rates, yet are rarely disclosed. Similarly, considerable costs related to retired capacity can continue to be recovered in base rates between rate cases. Yet such costs are neither disclosed in the IRP, nor included in the NPV analyses. These costs contribute to higher rates and should be disclosed in order for the Commission to fully appreciate the impact of the utility's resource decisions.

In addition, given the complexity of the modelling, certain other parameters should be standardized across IRPs as well. For example:

- New investments in all fossil generation should be fully depreciated by 2035 unless equipped with carbon capture.

- Sensitivity analyses should be the primary analytical tool (as opposed to stochastic analyses) to evaluate assumptions regarding commodity prices, capacity and energy prices, resource capital costs, and load growth. Stochastic modeling is intended to add potential randomness or volatility of key assumptions, but the stochastic results do not inform the Commission about the *range of potential impacts*. A sensitivity analysis, on the other hand, is used to help determine a model's *overall uncertainty*, an analysis that is at the core of determining the reliability of a utility's preferred portfolio.

The utilities argue that formal Commission involvement in the IRP process is not needed, because ultimately any decision will be scrutinized when the utility files a CPCN for approval. Unfortunately, this is too little, too late because by the time those cases are filed, the utility has already taken significant action to implement its own "Preferred Portfolio" by issuing Requests for Proposals (RFPs), announcing the shutdown of existing plants, and entering into contractual arrangements with project developers. In fact, the Indiana utilities have become quite skilled in gaming the process by dividing requests into multiple CPCN filings so the entirety of the requests are not considered as a whole. Moreover, IRPs are frequently presented as "evidence" in CPCN cases. As a result, the Office of the Utility Consumer Counselor (OUCC) and consumer intervenors must litigate both the wisdom of the utility's individual project proposal and all of the underlying assumptions in a flawed IRP, with limited time and resources.

Also problematic is the failure of the utilities to have a "Plan B" because they have become so committed to their preferred portfolio. Perhaps that is because they believe not having a Plan B will leave the Commission little choice but to approve their CPCNs. Plan B's are needed simply as a good business practice. For example, FERC could reject a gas pipeline request, which effectively kills a new capacity project, even if the Commission has approved it. What decisions would the utilities have made differently in their IRPs if they had done a sensitivity analysis to determine the impact of MISO increasing capacity prices by 50-fold?

Often these generation decisions are made before stakeholders even have the opportunity to file comments with the Commission on the IRP. The "toothpaste is out of the tube" by the time a CPCN case is filed. At that point, the opportunity has passed to fix a problem or error that could have changed the outcome of the IRP, and the action the utility undertook as a result. Although nonbinding, IRPs certainly set expectations for future resource procurement, rate and cost recovery, and customer demand side management (DSM) programs. There is no counter-balancing influence in the informal IRP process to the utilities' financial incentive to rapidly retire reliable baseload generating resources that still have significant useful lives, and invest their capital in new generation at above-market prices, so they can receive the highest returns for their investors.

No change in law is necessary for the Commission to formalize its involvement in IRP development. The Commission has authority to initiate an investigation into all matters relating to any public utility pursuant to IC 8-1-2-58. A formal IRP proceeding would include:

- The IRP and its supporting documentation becoming part of the evidentiary record, making the process (and the generation decisions that eventually stem from it) transparent, and more likely to be fairer to customers;
- The utility, as well as intervening stakeholders, would have the opportunity to provide sworn testimony through witnesses during public hearings to formally support or critique the IRP;
- The Presiding Officers would be available to resolve discovery disputes that cannot be resolved among the parties;
- Parties would receive official notice of new developments in the proceeding, such as deadlines and filed comments from others, rather than relying on periodic checks of the Commission's IRP website for updates.

Regardless of what procedure is used by the Commission, because of the dynamic nature of power and energy markets, an IRP cannot substitute for a full evidentiary justification of future resource requests when they are filed. However, the outcome of a formal IRP process could include the Commission:

- Providing guidance as the IRP development process unfolds, such as requests to the utility for particular actions to avoid errors, balance interests, and encourage reasonable outcomes;
- Balancing requests for changes to the IRP modeling, taking into consideration awareness of market and regulatory constraints, as well as motivations and interests of the parties;
- Providing specific comments on the methodologies, assumptions, programs, etc.;
- Defining how customer affordability is measured uniformly and accurately across utility IRPs;
- Addressing issues of reliability and resilience, and protecting the public interest;
- Clarifying questions or seeking additional information regarding the IRP;
- Discussing past IRP analysis, Director Report recommendations, or regulator actions on IRPs in other states where the utility operates; and
- Supporting the parties in working together towards new solutions or alternative approaches to IRP development.

Reliable Energy respectfully urges the Director to support formalizing the Commission's involvement in the development of utility IRPs, and to balance the interests of utilities and consumers. **Formal feedback from the Commission on an IRP or its development process would not pre-approve any project, nor would it bind the utility to any particular course of future action.** Reliable Energy has confidence that a far more balanced result would occur from formal IRP proceedings before the Commission.

III. THE DEI IRP

Duke Energy Indiana (DEI)'s capacity mix is shown below. With the three remaining coal units, over 90% of its installed capacity is coal based:

Resource	Type	2021 ICAP
Cayuga 1&2	Coal	1005
Edwardsport IGCC	Coal	618
Gibson 1-5	Coal	2845
		4468
Noble CCGT	Gas	310
Solar	Renewable	47
Wind	Renewable	100
		147
PPA	Capacity	50
Total		**4975**
Coal Percent		**90%**

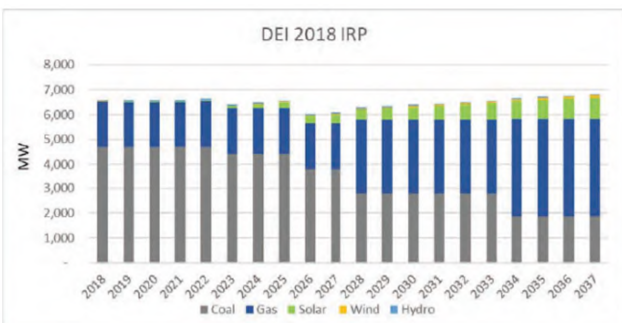
DEI plans to reduce reliance on coal via combined-cycle gas turbines (CCGT), combustion turbines (CTs), and renewables. While CCGTs are considered to be base load dispatchable resources, CT's (which are higher cost) are generally only used as a backup to renewables. Like coal, CCGTs have substantial greenhouse gas emissions related to combustion, as well as upstream emissions. It is unclear how CCGT fits into a "net zero regime" unless it is retrofitted with carbon capture or the ability to convert to green hydrogen materializes.

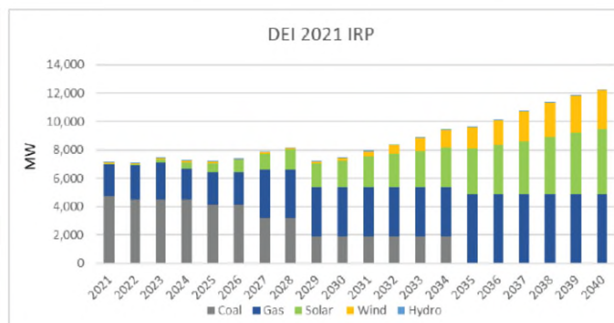
DEI also plans significant solar additions in the next five years, as reflected in the chart below:

			Cumulative (MW)		
Year	**Coal Retirements**	**Gas Additions**	**Solar**	**Wind**	**Solar + Storage**
2021	Gallagher 2&4 (280 MW)		47	100	
2022			47	100	
2023			187	100	
2024			447	100	
2025	Gibson 5 (313 MW)		647	100	
2026			847	100	
2027	Cayuga 1&2 (1005 MW)	CCGT (1221 MW)	1047	100	75
2028			1247	100	150
2029	Gibson 3&4 (1262 MW)		1497	100	225
2030			1547	200	300
2031			1697	200	450
2032			1847	600	525
2033			1997	900	600
2034			2147	1200	675
2035	Gibson 1&2 (1279 MW), Edwardsport Coal Gasification (32 MW)	CT (1160 MW)	2297	1500	900
2036			2447	1800	975
2037			2575	2100	1125
2038			2725	2400	1275
2039			2875	2600	1425
2040			3025	2800	1500

There is increasing evidence of problems with reliance on future solar generation additions by load-serving utilities. In addition to supply chain problems and higher costs, the U.S. Department of Commerce is investigating whether Chinese companies are circumventing U.S. tariffs by selling components for solar panels through four Southeast Asian countries. **As a result of this investigation, the Solar Energy Industries Association (SEIA) has lowered its solar installation forecast by 46% for 2022 and 2023.[8]** This prediction has been recognized by other major utilities in Indiana. AEP acknowledged in its Q1 2022 investor call that solar is behind schedule and is coming in at higher than expected cost.[9] NIPSCO is delaying the retirement of the Schahfer station because of delays in its solar projects.[10]

DEI presents its capacity outlook on an installed capacity basis (ICAP) which differs from other Indiana utilities. AES Indiana presents both ICAP and UCAP and CEIS's presentation is based solely on UCAP. UCAP is the metric upon which compliance with reserve requirements is measured. As renewables have considerably lower UCAP, more installed capacity is needed to meet resource requirements. Below, the preferred portfolio from the 2021 IRP is compared below to the preferred portfolio from 2018.





The difference between the two IRPs is substantial, as the coal fleet is now fully retired by 2035. Note that in the 2018 IRP, total ICAP was relatively flat. This is not the case in the 2021 IRP due to the lower UCAP for renewables. Significant capacity additions in the 2021 IRP reflect the additional ICAP needed when there is heavy reliance on renewables.[11]

The change in the 2021 IRP appears to be a top down approach dictated by management decisions, as Duke Energy revised its corporate objective to be less than 5% coal by 2030 and a full exit from coal by 2035.[12] It should be noted that Duke Energy's focus is on reducing coal

[8] https://pv-magazine-usa.com/2022/04/27/seia-cuts-solar-deployment-forecast-46-in-light-of-anti-circumvention-investigation/

[9] Full Earnings Call transcript: https://seekingalpha.com/article/4504662-american-electric-power-company-inc-aep-ceo-nick-akins-on-q1-2022-results-earnings-call

[10] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/nisource-expects-solar-project-delays-extends-life-of-ind-coal-plant-70152518

[11] If the UCAP for renewables is reduced, greater capacity additions would be required.

[12] https://news.duke-energy.com/releases/duke-energy-expands-clean-energy-action-plan

generation, not zeroing out carbon emissions, which allows the Company to argue in support of the proposed switch to natural gain its "carbon plan".

IV. PROBLEMS WITH DEI'S PREFERRED CASE

There are numerous problems with DEI's preferred case, some of which DEI readily admits. Others are problems related to key assumptions.

The problems to which DEI admits are that during this transition period, there is considerable uncertainty as to which technologies will make economic sense. Frankly, it is refreshing to have the utility acknowledge this concern in an IRP. Not just utilities are uncertain about the transition to renewables and new technologies. Recent articles address a similar concern for truck makers, stating they face a major dilemma regarding the future use of battery electric vehicles or hydrogen fuel cells.[13] Notably, the truck industry appreciates the magnitude of the stakes that could be involved in making the wrong decision. For utilities, it is even more complicated as the options are greater than simply batteries or hydrogen. The options also include nuclear and carbon capture, as well as renewables.

In the IRP, DEI qualifies its discussions about hydrogen, stating its forecast is "pending development of a reliable supply of cleanly sourced hydrogen fuel", assuming "fully-hydrogen capable combustion turbines (CTs) will be commercially available to be deployed by 2035", that the "turbines deployed in the 2020s would be modifiable to support additional hydrogen capability", that the forecasts are "dependent on the development of technology to cost effectively produce and transport green hydrogen (or ammonia))", and "most notably the hydrogen economy needs to provide a reliable fuel supply".[14]

Most impressively, DEI affirmatively states that "**(a)t this time, it is not yet clear whether hydrogen will advance more quickly or less quickly than other emission-free, dispatchable generation options, such as nuclear small modular reactors (SMRs), advanced long-term storage, or carbon capture utilization and storage [CCUS].**"[15,16] Given this admission, Reliable Energy believes that DEI's IRP cannot and should not be counted upon to determine what the desirable options are for replacing its coal fleet in the future.

We agree with DEI that it is unclear whether green hydrogen can be produced in an economic manner and it is uncertain whether the planned CTs and CCCTs can be built to burn either a blend of natural gas and hydrogen and/or hydrogen alone. We also agree that certain non-hydrogen technologies hold promise including SMRs advanced storage, and CCUS.

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[13] https://www.nytimes.com/2022/04/11/business/electric-hydrogen-trucks.htmland https://www.transportdive.com/news/hyzon-nasdaq-hydrogen-fuel-cell-electric-truck-EV/603531/

[14] 2021 IRP, page 19.

[15] *Id*.

[16] Duke Energy recently announced it is working with Purdue University to explore using SMR technology to power Purdue's electricity demand, *Indianapolis Business Journal*, April 27, 2022.

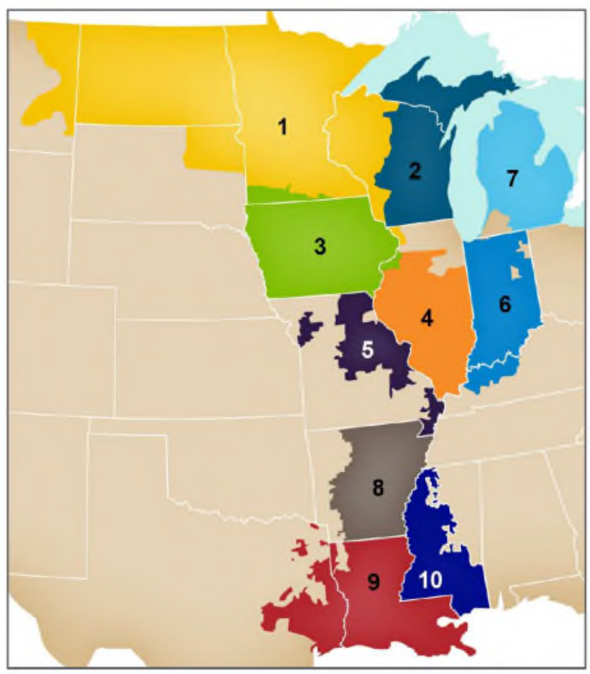
In performing its analyses, DEI of course had to make assumptions regarding these technologies, fuel costs, regulations, and the like. With DEI's qualifications, definitive decisions as to which approaches should be pursued cannot be made at this time. This includes DEI's proposed more than billion dollar investment in a new CCGT.

While Reliable Energy has identified a number of problems with DEI's IRP assumptions, we focus here on the two that we think are the most relevant at this time: the assumed capacity price in DEI's analysis and the economics of the CCGT. Both of these are particularly relevant given DEI's proposed closure of Gibson 5 in 2025 and Cayuga in 2027 and the replacement of this capacity with 1200 MW of combined cycle capacity in 2027.

For a number of years, Reliable Energy and others have raised a concern about capacity prices in MISO Zone 6, given that only a portion of the actual and announced coal plant retirements are being replaced with dispatchable resources. On April 14, 2022, MISO announced the results of its most recent capacity auction. As shown below, Zone 6 capacity prices are about $240 per MW-day[17], almost a 50-fold increase from the prior auction which was $5 per MW-day. As noted, the increase reflected capacity shortfalls which resulted in the use of Cost of New Entry (CONE) to establish the pricing.

Clearing prices from MISO's 2022-2023 PRA reflect capacity shortfalls in four zones, exposing nearly 8 GW in MISO North/Central to the Cost of New Entry

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$236.66
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$236.66
3	ALTW, MEC, MPW	$236.66
4	AMIL, CWLP, SIPC, GLH	$236.66
5	AMMO, CWLD	$236.66
6	BREC, CIN, HE, IPL, NIPS, SIGE	$236.66
7	CONS, DECO	$236.66
8	EAI	$2.88
9	CLEC, EES, LAFA, LAGN, LEPA	$2.88
10	EMBA, SME	$2.88
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$133.70-236.66



17 https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf, page 4.

MISO noted that it did not believe this was a one-off event. According to MISO "(u)nless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year's auction will continue." MISO also noted that "Zones 1-7 have an increased risk of needing to implement temporary, controlled load sheds."[18] As provided most recently in Reliable Energy's comments on the NIPSCO IRP, this capacity price increase has been experienced by others.

Unlike other utilities, DEI did not share explicitly what its market capacity assumptions were in its IRP documents. From confidential information confirmed directly with DEI, Reliable Energy was told that DEI assumed that the capacity price would be DEI's carrying cost of the new combustion turbines. The MISO auction results were significantly higher than the cost assumed by DEI.

Without sufficient replacement capacity for Gibson 5, DEI may need to purchase up to 300 MW of capacity on the open market. At the new capacity price, 300 MW of capacity would cost over $23.6 million per year.[19] If the capacity rate had remained at $5 per MW-year, the cost would have been less than $500,000. DEI needs to reconsider the timing of this retirement given the significant financial burden it would place on ratepayers if MISO is correct that the high prices are likely to recur and/or increase.

Reliable Energy has similar concerns for Cayuga. As noted above, DEI acknowledges that an **assumption** in the IRP is that the "turbines deployed in the 2020s would be modifiable to support additional hydrogen capability" and that the capability of CTs to operate on 100% hydrogen remains dependent on the development of technology to cost effectively produce and transport green hydrogen (or ammonia)."[20] For this position, DEI is reliant on the representation from turbine manufacturers "that existing turbines have the ability to blend approximately 30% by volume today" and "will have the ability to be fire 100% H_2 by 2035."[21] In other words, there is no certainty as to the future conversion capability and there is no apparent inclusion of the associated conversion costs.

It is misleading for DEI to state that it "built its preferred portfolio to be flexible so that it can pivot to the most cost effective and reliable technology available at the time."[22] Building a CCGT to replace Cayuga would be a commitment that significantly decreases DEI's flexibility. The conversion capability is equally a concern for the CCGTs as it is for the CTs. In other words, if the CCGTs cannot be converted to 100% hydrogen and/or green hydrogen cannot be produced economically, the replacement of Cayuga will have significant long-term cost implications as customers not only continue to pay for the stranded costs associated with

[18] https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf at page 9.

[19] MW * EFOR (90%) * 240

[20] IRP page 19.

[21] IRP page 36.

[22] IRP page 19.

Cayuga, they will also be asked to pay for the future stranded costs associated of the CCGT replacement by 2050, well ahead of its assumed plant life.

Deferring retirement of Cayuga would provide the time necessary to determine what would be the appropriate replacement technology, would reduce the total amount of stranded costs associated with Cayuga and would defer the costs to ratepayers associated with the return of and return on the new capital associated with the incremental resource investment. Significant new investment in gas plants is speculative at this time if it is reliant on future conversion to green hydrogen. Therefore, Reliable Energy believes that if DEI wants to include new gas in its preferred portfolio it must be demonstrated to be economically justified assuming either (1) a shorter economic life based upon a 2035 retirement, or (2) a carbon capture retrofit in 2035.

We note that in the scenario Reliable Energy asked DEI to consider, the costs of the CCGT assuming the shorter life were considerably higher than the costs DEI used in the other cases, as DEI made no adjustment for an environmental plan that would preclude the use of natural gas after 2035. Unfortunately, in the DEI scenarios, DEI did not consider an abbreviated life for the CTs or CCGTs. If the new gas investments cannot be economically justified over the shorter life and DEI did not believe it had sufficient certainty about the costs and availability of green hydrogen, or hydrogen's ability to displace natural gas, the gas options as presented do not represent reasonable options for resource replacement.[23]

The natural gas additions are also problematic for other reasons. The 1221 MW CCGT proposed for 2027 will face serious challenges from environmental groups at the state and federal levels for the reasons mentioned above, i.e., high carbon emissions, both upstream and at the plant. Such challenges could delay a plant well beyond its needed in-service date. In addition, the natural gas prices assumed by DEI may not reflect the changes to the market that some analysts believe will persist. In short-term, the increases were caused by a rapid economic recovery from the impacts of the COVID-19 pandemic, which caused demand to exceed supply. Further, coal supply was unavailable to support higher levels of coal generation, effectively eliminating the cap on gas prices that coal has provided for the last decade or so. The increase in gas prices which occurred in the last nine months could become permanent as coal plant retirements eliminate the historic economic feedback loop between coal and gas, i.e., coal generation cannot increase to offset high gas prices. In fact, DEI concluded in the IRP that "(h)igher gas prices increase the power price and keep coal generation operating through the term of the IRP."[24]

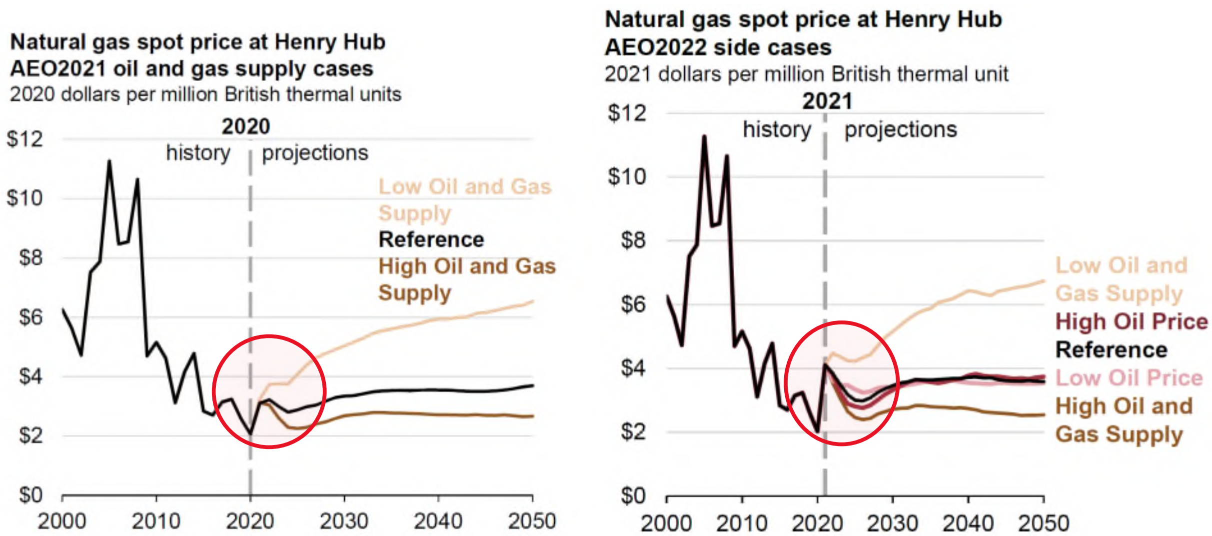
DEI did not provide sufficient narrative about its gas price forecast other than mentioning it was prepared by IHS and is confidential. This is unacceptable, particularly given DEI's stated

[23] One alternative could be the assumption that in 2035 a CCGT would need to be retrofit with CCUS in order to continue to operate. This option was also deemed too uncertain to continue.

[24] IRP, page 96.

preference to increase its reliance on natural gas. If IHS will not allow its forecast to be included in the public document, then DEI either needs to produce its own forecast or find a consultant that will.

DEI indicates it uses the range in the Annual Energy Outlook (AEO) forecasts to help form the high and low cases. As shown below, the AEO forecasts changed materially between 2021 and 2022:



The 2022 forecast was significantly higher than the 2021 forecast, even assuming a small adjustment to put the real dollars from each year on the same basis. DEI acknowledged the significance of higher gas prices in the IRP. "In 2021, natural gas prices increased considerably and pushed up power prices; in response to this, the Company reduced energy market purchases and increased generation as another way to protect customers and has shown that the coal fleet is a good hedge against increased gas and power prices."[25] Unfortunately, in its haste to propose retirement of the coal fleet, DEI is forgetting this fundamental point. The combination of a shorter depreciation period and higher gas prices could have a meaningful impact on the economics of this resource options.

It should be noted that DEI casually throws into its narrative a desire that new gas be hydrogen capable.[26] This follows its acknowledgement that "hydrogen as a utility fuel is still in the early stages from both a production and generation standpoint." DEI further states "to move to 100% hydrogen-fueled turbines substantial improvements in turbine technology are required.

[25] IRP page 64.

[26] IRP page 7.

Additionally, hydrogen production would have to increase by many orders of magnitude to have ample supply to match the current production output of natural gas-fueled turbines."[27]

V. Conclusion

Reliable Energy appreciates the opportunity to participate in the IRP stakeholder process and to offer comments on an ongoing basis. Reliable Energy also appreciates DEI's willingness to engage in a robust discussion of the issues. Reliable Energy would be happy to discuss the issues raised above further with Commission staff.

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[27] IRP pages 173-174.