**RELIABLE ENERGY'S COMMENTS**
**ON INDIANA MICHIGAN POWER'S 2021 INTEGRATED RESOURCE PLAN**
**August 3, 2022**

## I. INTRODUCTION AND SUMMARY

Reliable Energy participated in the stakeholder process and conducted a review of the Integrated Resource Plan (IRP) that Indiana Michigan Power (I&M) submitted to the Indiana Utility Regulatory Commission (IURC or Commission) on January 31, 2022. 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.

On March 24, 2022, Reliable Energy filed comments on the Northern Indiana Public Service Company (NIPSCO) IRP, and submitted comments on the Duke Energy Indiana IRP on May 16, 2022. Reliable Energy has concerns about the IRP process that is common to all three filings which we repeat here. In addition, Reliable Energy has specific concerns about I&M's IRP which are discussed as well.

I&M and its parent company, American Electric Power (AEP), aim to achieve net zero carbon dioxide emissions by 2050. In the meantime, I&M intends to grow its renewable generation portfolio by 1,700 MWs by 2030. These types of statements from 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.

Meanwhile, just last week MISO issued a *system-wide* maximum generation alert with temperatures soared across the Midwest, and several Indiana utilities warned customers[1] of the potential for rolling blackouts caused in part, to the closing of coal-fired generation plants across the country, and the high demand for power. Notably, Reliable Energy has been warning the utilities and the Commission for some time in various forums that capacity availability is a concern as coal plants are retired prematurely. These concerns have worsened because of the strong recovery from COVID, combined with the Russian invasion of Ukraine. The net result is significant impairment in the supply chain, higher commodity prices for fuel and the critical minerals needed for renewables produced outside the U.S., and labor shortages. Of course, the

[1] See links to customer notices from: *Bartholomew County REMC*; *Clark County REMC*; *Daviess-Martin County REMC*; *Dubois County REC*; *Jackson County REMC*; *Johnson County REMC*; *NineStar Electric*; *Orange County REMC*; *RushShelby Energy*; *South Central Indiana REMC*; and *Utilities District of Western Indiana REMC*.

Russian invasion in Ukraine occurred subsequent to the filing but could result in a change in the global economy for decades to come.[2] Some utilities have been forthright in announcing delays and higher costs related to their plans for procuring replacement capacity for their planned coal retirements, but others have been less so. The 2021 I&M IRP, despite not being filed until January 2022, did not reflect the significant impact of the robust economic recovery that started in the second half of 2021.[3] It is also important to note that NIPSCO announced it is delaying the retirement of two Schahfer Generating Units due to a federal solar tariff investigation by the U.S. Department of Commerce. The two units were scheduled to retire in 2023, and will now retire in 2025 due to expected 6-18 month delays in the replacement capacity from its planned solar projects.[4] While President Biden recently announced duty-free imports of solar modules from Cambodia, Malaysia, Thailand, and Vietnam for 24 months, this will not fully solve the supply chain and regulatory delays, and the Commerce Department investigation continues.[5]

While I&M is a member of PJM, the most recent capacity Planning Resource Auction (PRA) in MISO should be considered because it reflects rising costs that are being experienced by the electric industry across the country. Accelerated coal plant retirements combined with delays in capacity additions created this problem. Higher capacity prices generally increase ratepayer costs. For the 2022/2023 MISO planning year, there is almost a *50-fold increase* in capacity prices, from $5/MW-Day to almost $240/MW-Day. There are similar concerns in PJM. In fact, in Cause 45546, I&M in part justified the buy-back of Rockport 2 due to capacity availability issues.[6]

AEP's First Quarter 2021 Earnings call[7] by CEO Nick Akins addressed a concern raised by Sophie Karp of KeyBanc regarding how supply chain disruptions could affect the project pricing the company originally received in response to its RFPs and how that might change the Company's integrated resource planning:

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[2] One notable change is the reversal in the Presidential Administration's position on oil and gas drilling. The Department of Interior announced it will begin auctioning leases for drilling on more than 144,000 acres of government land in nine different states. https://www.doi.gov/pressreleases/interior-department-announces-significantly-reformed-onshore-oil-and-gas-lease-sales

[3] "The COVID-19 Pandemic had a significant impact on residential and commercial usage. With more people at home, residential usage increased by 1.6% in 2020. Meanwhile, with the economy shutdown, commercial usage declined by 5.2% in 2020." IRP page 44.

[4] NiSource 4th Quarter 2022 Earnings Call (May 4, 2022): https://www.nisource.com/news/article/nisource-reports-first-quarter-2022-results-20220504

[5] https://www.utilitydive.com/news/biden-to-pause-solar-tariffs-24-months-southeast-asia-commerce-module-probe/624928/

[6] "Mr. Thomas testified that I&M will also be able, prior to the Closing Date, to commit Rockport Unit 2 as a capacity resource to meet its obligations as a member of PJM." Final Order in Cause No. 45546 (December 18, 2021), p. 5; *see also* "In Section A.2 [of the Settlement Agreement], I&M commits to utilize capacity from its share of Rockport Unit 2 to fulfill its FRR capacity obligation to PJM from December 8, 2022 through May 31, 2024." *Id.* at pp. 12-13.

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

**Sophie Karp**

> Perfect. Thank you. My other question is on the RFPs, not to beat the dead horse, I guess, but I can appreciate the fact that the projects are expected to be commissioned in 2024, 2025 timeframe, which is a couple of years away to sort out the physical disruption of equipment availability, et cetera. But in terms of pricing, what should be - typically bid into those RFPs, like what do you think they should be coming in terms of pricing. Does that make it difficult with volatility in the pricing of equipment, particularly solar, and unpredictability really where we are with the solar market or storage market might be a year from now. Does it make the, I guess, the process more complicated or addressed with it?

**Nick Akins**

> Yes, I think it will make it more complicated, but not insurmountable, because whatever increases you may see from a solar perspective, the overall project benefits will still be part of it. Now it may change the relationship between wind and solar in the integrated resource plan.
>
> Solar may come later than what we thought because if wind continues to continues to progress as you go in our resource plan, a lot of it was when to start and then eventually it's based on pricing and everything else, solar would start to pick up and at some point overcome the wind asset and then you move into other technologies. That condition may change based on that, but you also, I mean, you'll probably see that in the framework of increased gas prices too. So really the renewables will be relative to each other not in terms of relative to whether they'll get done or not. So, and I really think we'll be in good shape from that perspective.
>
> The other part two is that, when you look at the other resources, really what you're doing is, you're putting in renewables and you're also layering in some natural gas in the plan to really give it 24/7 supplier. Natural gas also is a placeholder for other types of resources, whether it's hydrogen, whether it's small modular reactors, whatever that comes about with new technologies and the grid optimization itself will be a major part of that as well with transmission.
>
> So there is a multitude of answers there that will occur. But, yes, you're right, you would suspect solar, there'll be some short-term perturbation from an increase perspective that we'll have to deal with. But in the overall scheme of things, when you look at long-term, it will still be positive.

Therefore, AEP recognizes that solar is behind schedule and higher cost, and this could affect its IRPs. However, Reliable Energy questions AEP's belief that simply "shuffling the deck" of resources is a reasonable means of assuring reliability and lowest cost. As we have discussed in other IRP comments and note in more detail below, natural gas is not a guaranteed placeholder given the problems with pipeline permitting and AEP's own admission that without significant carbon credits, natural gas may not be an economic resource. AEP's suggestion that installation of wind resources can make up for the delay in solar projects is also unreasonable because it ignores the fact that more than twice as much wind capacity must be installed to get the same unforced capacity rating (UCAP) as solar.

Reliable Energy recognizes the energy industry is in transition, and urges the Commission to consider the broad impacts of significantly changing the composition of utility generation portfolios over a very short period—not simply accept pressure from utilities and their shareholders to decarbonize the grid at the expense of grid reliability, resilience, and the customers' pocketbook. Moreover, the Commission should act responsibly and assure that regulated utilities maintain existing electricity generating assets in Indiana as renewables come online.

The primary flaws in the IRP process are threefold:

- *First*, the IRP process itself has gotten out of control. Often, millions of dollars and years of effort are spent by the stakeholders and the utilities in advocating and analyzing scenarios, many of which become irrelevant by the time the IRP is issued as a result in changes in markets, technologies, the economy, and regulatory obligations. 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.[8] 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. The lack of hearings in front of the Commission limits the Commission's engagement and the fairness of the process. Worse, neither the utilities nor the Commission consider how an individual utility's plans are affected by the collective activity of the other utilities in the state or in the relevant RTO market.

- *Second*, the IRP development process fails to take into account the rapidly changing energy market, or balance the interests of the utility to maximize profits in modeling its resource decisions. Capacity prices are high, and utilities will be running their coal units throughout the summer, at the same time they are telling the Commission that those units are no longer a valuable or useful part of resource portfolios, and should be retired. The IRP metrics used by I&M do not provide an accurate assessment of the costs of resource decisions, nor does the model adequately address reliability, resiliency and market risk.

- *Third*, while I&M's Preferred Portfolio will have tremendous impacts on customer costs, service reliability and resiliency—I&M/AEP admits that its plan may not even be possible

[8] The prior I&M IRP was filed July 1, 2019. The Director's Final Report was published February 2, 2021, 586 days later. (Note the date of the Final Director's Report is shown as February 2, 2020 on its cover page. This is a typographical error. The correct date (February 12, *2021*) is included in the URL.)

without significant developments in technology and changes in environmental laws that will make its plans truly realistic and economic. Reliable Energy and its predecessor organization have witnessed how the flaws in the IRP process have (and, left unchanged, will continue to) produce higher power rates as a result of: growing stranded costs; over commitment by utilities to long-term power purchase agreements; new commitments for capacity that could be stranded well ahead of the usual economic life for generation assets; and greater exposure to reduced utility reliability and resilience. Overall, the IRP process has become too mechanical and less strategic as the utilities spend enormous resources in modeling and stakeholder involvement, and less time in considering ratepayer impacts, how best to ensure system reliability, and how other utilities in Indiana and nearby states could be relevant to their choices.

Reliable Energy provided specific comments on its concerns regarding the I&M IRP to the utility in March 2021. These comments were largely unaddressed and are incorporated in this document as an attachment.

The remaining comments are organized in two major sections as follows: (1) Process and Evidentiary Issues; and (2) Problems with I&M'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 impact 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 decisionsare 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. SIGNIFICANT FLAWS IN THE I&M IRP

### I&M's Preferred Portfolio

I&M's Preferred Portfolio provides for the retirements of the Rockport units by 2028 and replacement of these resources, largely with renewables and gas combustion turbines, through 2036. The Preferred Portfolio assumes the closure of the Cook nuclear plant in 2036 with the base load capacity at that time replaced by Combined Cycle Gas Turbines (CCGTs). I&M has not ruled out continued operation of the Cook nuclear plant after 2036 and plans to investigate what investment would be needed for a 20-year extension of its operating life.

The obvious problems with the Preferred Portfolio are the reliance on natural gas additions including both Combustion Turbines (CTs) and CCGTs, throughout the forecast period and the very significant renewable additions over relatively narrow periods:

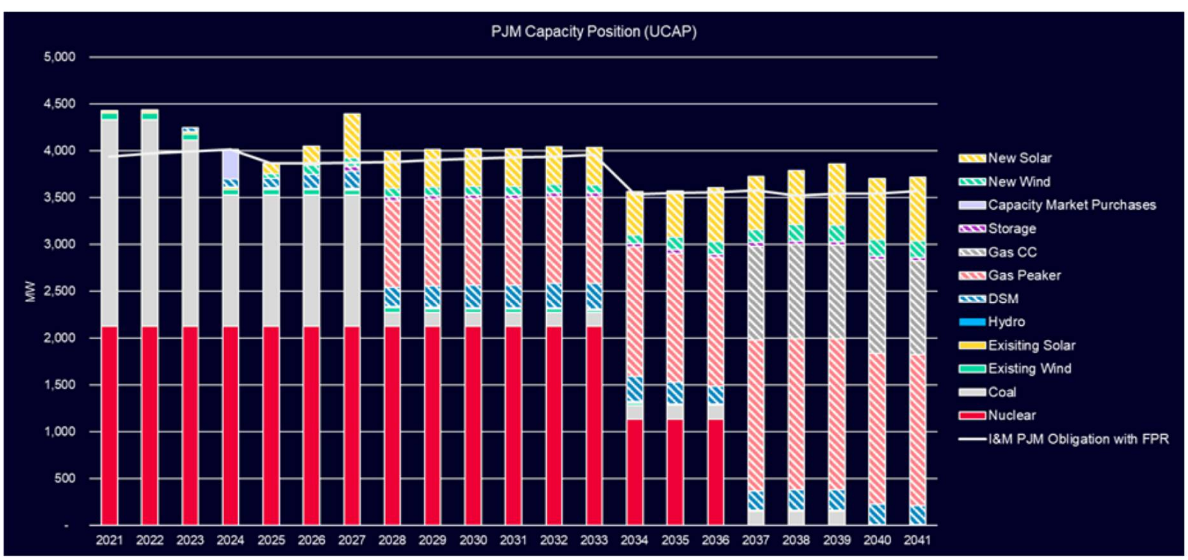


Figure 5. I&M's Preferred Portfolio - PJM Capacity Position (UCAP)

## Compliance with Corporate Clean Energy Goals

In February 2021, AEP announced its corporate clean energy goals.[9]

- Achieving net zero carbon dioxide emissions by 2050, with an interim goal to cut emissions 80% from 2000 levels by 2030.
- Growing its renewable generation portfolio to approximately 50% of its total capacity by 2030.
- Adding approximately 16,000 megawatts of regulated wind and solar through 2030.
- Investing $8.2 billion in renewables through 2026.
- Continuing to invest in a smarter, more modern power grid.
- Educating customers on how to optimize their energy efficiency.
- Advocating for and enabling wider usage of electric vehicles.

This plan--which will have tremendous impacts on customer costs, and service reliability and resiliency--is relegated to only a footnote in the Executive Summary of I&M's IRP. While not fully discussed in Appendix IV, AEP confirms that the Preferred Portfolio is inconsistent with these corporate goals, absent the availability of $100 per ton carbon offset, because of the IRP's reliance on natural gas. The basis for this assumption is not provided.[10]

Further, AEP argues in its Climate Impact Analysis Report by the Company's Task Force for Climate Related Financial Disclosure (TCFD) that "it is important that a CES ["Clean Energy Standard"] provide partial credit for natural gas in the near-term as well as full credit for nuclear. In the first decades of such a program, natural gas and nuclear are critical to providing 'firm' energy sources to support intermittent renewable energy."[11] This is a remarkable statement, suggesting building new natural gas resources without a significant carbon credit may not be economic.

**Reliance on Natural Gas CTs and CCGTs**

Assuming the CCGTs are installed in 2036, they should be evaluated over a 14-year life given the uncertainty as to the availability and costs of offsets. It is not fair to depreciate this plant over a longer life, because if the plant cannot continue to operate after 2025, all that has been accomplished is the creation of yet another stranded utility asset. Alternatively, a new CCGT must be justified with carbon capture.

Similarly, CTs need to be evaluated over a shorter term. This is particularly important given the entire I&M IRP is dependent upon the construction of the CT's to provide capacity back up. Yet, the project's capital is only part of the CT cost. In order to qualify capacity, Firm Transportation

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[9] https://www.aep.com/about/ourstory/cleanenergy

[10] https://www.in.gov/iurc/files/IndMich_2021-IRP-Volume-4-Appendix_01312022.pdf, pages 281, 283, 297, and 321.

[11] *Powering Forward To Net-Zero: AEP's Climate Impact Analysis, A TCFD Report* (March 2021), http://www.aepsustainability.com/performance/report/docs/AEPs-Climate-Impact-Analysis-2021.pdf at p. 14.

is also required. In the recent CPCN for CenterPoint, the Firm Transportation actually exceeds the cost of the CTs.

**CONCLUSION**

**I&M's resource plan is hypothetical.** I&M notes that in the long-term, "the nation will depend on **sources of power that are now not fully developed and cost-effective**. These include carbon capture, utilization and storage (CCUS) for natural gas, advanced energy storage, and new power sources[12] *that are today more conceptual than reality*, such as the use of hydrogen. **It will take decades to develop those new technologies to support a clean energy economy and require a federal research and development program and coordination with the energy sector that would be unprecedented in scope and scale**."[13] Reliable Energy agrees with I&M. As a result, the IRP should not be considered a road map for I&M's future.

Now is the time for the Commission to change course. The antiquated and imbalanced IRP process cannot continue as it has for the last 40 years. Monopoly utilities are highly regulated in Indiana because absent the Commission's acting under its statutory duties, prices skyrocket and service suffers. Reliable Energy appreciates the opportunity to participate in the IRP stakeholder process and to offer comments. Reliable Energy would be happy to discuss the issues raised above further with Commission staff.

[12] While not stated in this quote, this presumably includes small modular nuclear reactors (SMRs) and green hydrogen.
[13] IRP, Page 92 (emphasis added).

# ATTACHMENT I

**Reliable Energy, Inc.'s Comments**
**on I&M's March 9, 2021 IRP Stakeholder Meeting and Slide Deck**

## 1. GENERAL

- Most forecasts are only provided through 2035, not the 2040 planning horizon
- The load forecasts should be reconsidered or better explained
- Stochastic modeling should be limited to variables which display volatility, not uncertainty

## 2. METRICS

| IRP Objectives | IRP Metric |
|---|---|
| Affordability | NPV-RR |
| Rate Stability | 95th percentile value of NPV-RR |
| Sustainability Impact | CO2 Emissions |
| Market Risk Minimization | Spot Market Exposure (Purchases/Sales) |
| Reliability | Reserve Margin |
| Resource Diversity | Mix of Adequate Resources |

Reliable Energy has the following problems with the proposed metrics and/or what they are being used to consider.

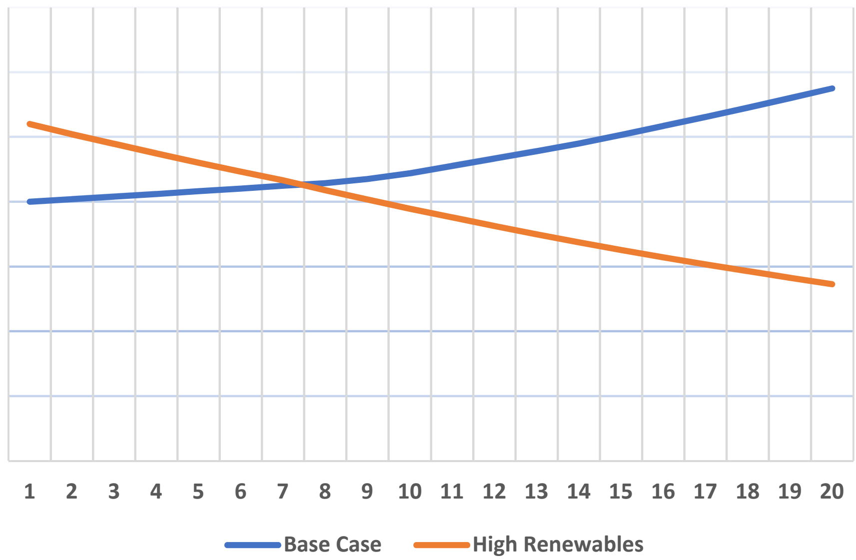
### Affordability

While it is appropriate for IMP to consider the impact to customer bills, the NPV-RR does not provide this.

- The NPV-RR is the net present value of revenue requirements. Revenue requirements are what the utility needs to support its operating system and is not the basis for rates. The largest difference is with respect to capital. Revenue requirements assume levelized costs. Rates are based on undepreciated capital. Given this disconnect, the two are not the same.

- Outer years have the greatest cost uncertainty. As these costs are discounted in determining the NPV, even with the expected increase in costs, the effect is muted.

- This can be seen in a simple example which compares the trajectories of annual revenue requirements. Over the 20-years, one scenario is the lowest cost. However, in the first five or 10 years, the other scenario is lower in cost. Given how rates are established, the rate impacts of the first case are likely to be greater than the rate impacts of the second case over the first 10 years.




The NPV's for this example are as follows:

| NPV Term | High Renewables vs. Base Case |
|---|---|
| 5 Years | 21% |
| 10 Years | 12% |
| 20 Years | -3% |

Note the 20-year NPV is lower but it is only lower because of the projected savings in the later years when there is greater uncertainty about future costs. To the extent, NPV's are used to assess customer affordability, they should be for the earlier periods, e.g., five and 10 years, when there is greater certainty as to costs and the future savings do not mask near-term costs.

**Rate Stability**

Again a statistical analysis of the NPV is being called upon to demonstrate rate stability. Rate stability should reflect stable prices over the planning period. The 95th percentile of the NPV does not show this.

**Sustainability Impact**

IMP's measure of environmental sustainability is carbon emissions. AEP has an announced goal to achieve net zero carbon emissions systemwide by 2050.[14] While AEP has an interim target of 80 percent reduction in carbon emissions from 2000 levels by 2030, for reasons discussed more fully below, using carbon emissions as the measure of sustainability is misplaced. The focus needs to be on the glide path to the net zero carbon emission target, not the level of carbon emissions. The strategy to get to net zero could be very different than the strategy to have lower carbon emissions. For example, new gas could reduce carbon emissions but may be contrary to the glide path for a low cost strategy for achieving net zero by a date certain.

**Market Risk Minimization**

IMP proposed to use spot market exposure (which it defines as purchases versus sales) as the metric for determining market risk. It is not obvious why this metric, as defined by IMP, is a measure of market risk minimization. Typically, market risk minimization is measured by the diversity, resilience, and reliability of generation. Unless IMP can demonstrate why a spot market exposure metric is appropriate, Reliable Energy believes an alternative metric for market risk be developed.

**Reliability**

IMP proposes the metric for Reliability be Reserve Margin. Utilities have a reserve margin obligation. It is not clear the relevance of achieving its required reserve margin is relevant as all cases must meet reserve margin to be acceptable. Reliability metrics should focus on the type of generation, on-site inventory, protection against gas supply disruptions, and insuring adequate transmission upgrades.

**Resource Diversity**

Resource Diversity is a separate metric for IMP. As noted above, Reliable Energy believes that Resource Diversity is part of Market Risk Minimization and Reliability, not a separate stand-alone metric.

## FUEL PRICE FORECASTS

IMP is reliant on EIA Reference case price forecasts for fuel. According to the deck, the forecasts are as follows:

[14] https://www.aep.com/news/releases/read/6051

**Fundamentals Forecast**

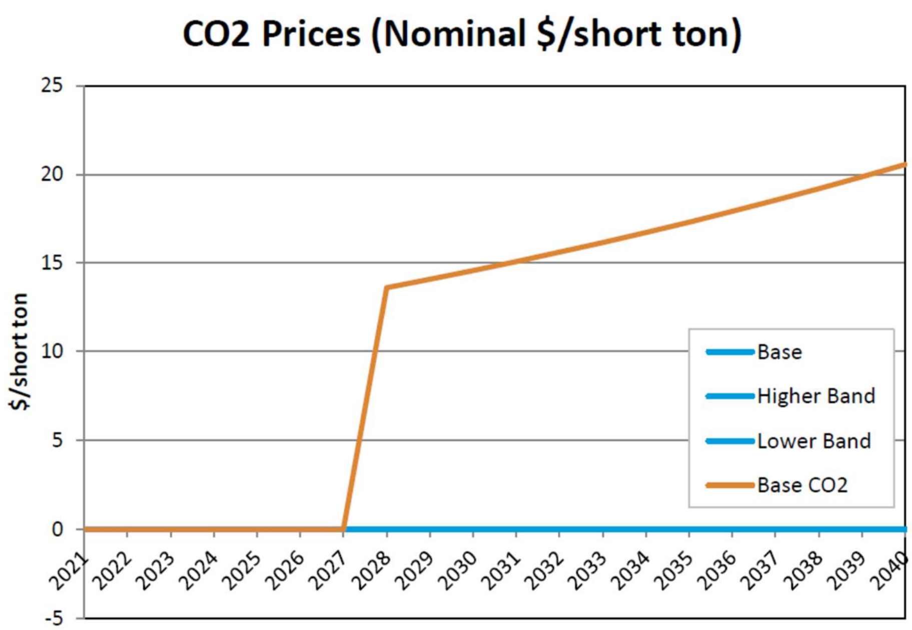
- Base Case: Reflects EIA Reference scenario with no carbon price assumption
- Base Carbon Case: Includes a $15/metric ton carbon price beginning in 2028, escalating at 3.5% annually thereafter
- High Case: Includes Base Case assumptions with high fuel prices (1 standard deviation) and higher loads
- Low Case: Includes Base Case assumptions with low fuel prices (1 standard deviation) and lower loads

The reliance on EIA price forecasts for IRPs is understandable as this is a public source. There are a number of problems, however, with such reliance and IMP's approach.

- The EIA reference price forecast does not reflect rules and regulations not in place.
- New regulations, such as a carbon regime, will affect future fuel supply and demand, hence prices. Therefore, the Base Carbon Case which uses the reference price with a carbon adder will not capture that market dynamic.
- Historically coal prices and natural gas prices are not correlated. Adjusting the base fuel prices upward and downward will miss a consequence of rising natural prices with flat coal prices, a scenario which is considered a real possibility.

### 3. <u>CARBON</u>

IMP is proposing to use the following carbon price in its Base CO2 case.




Carbon tax proposals are not new. Carbon taxes have. been proposed and rejected off and on for over 30 years.[15] For a variety of reasons, carbon taxes have not been legislated and are unlikely to be legislated. The problem with using a carbon tax is a carbon tax is <u>not</u> a proxy for all types of carbon regimes and It is particularly not a proxy for a net zero carbon goal by 2035, 2040, or 2050. Further, given the current composition of the Senate which not only has the slimmest

[15] https://priceoncarbon.org/business-society/history-of-federal-legislation-2 /

Democratic majority it has a Senator from West Virginia who heads the Energy and Natural Resources Committee. Senator Manchin has publicly stated his opposition to a carbon tax.[16]

There has been significant momentum related to carbon through the state adoption of Renewable Portfolio Standards (RPS) and Clean Energy Standards (CES). A Federal RPS is actually a smaller leap from where the U.S. is today than a carbon tax.[17] The reason to look specifically at net-zero plans, rather than using carbon prices as a proxy, is the modeling of net-zero plans versus carbon tax plans will produce different results. With respect to modeling, the largest difference is how new investments in fossil generation are handled. The modeling of new fossil generation should either consider the new investment over a truncated period or with carbon capture. If the investment is considered over a truncated period, i.e., 12-15 years, the full capital expense should be justified over that period. If the investment incorporates carbon capture, it can be for the entire life of the facility but can only assume 12 years of known 45Q credits if construction begins by January 1, 2024.

## 4. NATURAL GAS SUPPLY AND PRICING CONCERNS

Reliable Energy is concerned about natural gas supply and does not think the overview/price forecast adequately address concerns and costs related to:

- Future ability related to pipeline construction,
- Lack of natural gas storage growth as growth in consumption continues,
- Physical and cyber risks to pipeline delivery,
- Cost of Firm and Interruptible Transportation,
- Potential linkage between LNG and domestic natural gas pricing, and
- Methane controls at the wellhead.

## 5. RENEWABLE INTEGRATION

A large concern for the IPR's should be cost and constraints related to Renewable Integration. This should be discussed in detail at future meetings.

## 6. ALL SOURCE RFP

The All Source RFPs conducted by Indiana utilities have proven to be problematic and not good indicators of future costs. Using NIPSCO's last IRP as an example. NIPSCO materially underestimated the cost of new renewable generation in the prior IRP. While confidentiality limited public disclosure of the understatement, the Indiana Office of Utility Consumer Counselor (OUCC) filed testimony in October 2020, stating that not only were the resource costs higher than what had been assumed in NIPSCO's 2018, the IURC should consider whether the entire conclusions of the IRP be reconsidered.

> *This is no small issue considering that the wellbeing of NIPSCO's residential customers and the competitiveness of its business customers relies on keeping rates*

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[16] https://www.eenews.net/stories/1063724469

[17] https://www.c2es.org – 29 states have binding RPS, seven have CES, and another eight have voluntary programs.

*as low as reasonably possible. NIPSCO apparently made a misjudgment in its Short-Term Action Plan that solar resource prices would not substantially increase in the short term, leading to NIPSCO receiving much higher cost responses than available just two years ago in its first request for proposal ("RFP"). The effects of these misjudged costs will grow as NIPSCO presents additional solar resource proposals grounded in its Short-Term Action Plan, since the installed capacity from its current proposals represents about only 21% of the total amount of solar capacity envisioned in that Plan.*[18]

Vectren had similar experiences with its RFP. Vectren is currently experiencing a delay and significant cost overrun on a project for which it received approval. In May 2018 in Cause 45086, Vectren sought and ultimately received approval to construct, own, and operate a solar energy facility, referred to as the Solar Project. As part of the approval, Vectren is required to provide quarterly reports on the construction of the Solar Project. The report at the end of Q1 2020 indicated a significant problem and at least a four-month delay, which Vectren alleged to be related to COVID-19 although at the end of March 2020 there were limited COVID-19 impacts. Further, the EPC contractor withdrew. The report at the end of Q2 2020 showed over a 20 percent increase in project costs. This project had been challenged on the basis of need and cost and ultimately only went forward due to a settlement with the OUCC and the Citizen's Action Coalition.

The lessons from the recent experiences of both NIPSCO and Vectren are that the IRP assumptions regarding renewable pricing may not be achievable and that even an all-source RFP is not dispositive. Vectren, which had chosen to rely heavily on the results of the RFP, admitted as much. In the 4th Stakeholder Meeting Minutes provided in Volume 2 of the 2020 IRP, Vectren "found there are many difficulties with (the all-source RFP) process. The long timeframe makes it difficult for developers to hold their projects and pricing plus many projects are picked up by other groups while the IRP analysis is being performed." (Vectren Submitted IRP Volume 2 of 2 Part 1, p. 393 of 851).

IMP should explain how it plans to address the inherent uncertainty of the All Source RFP Process. Further, the All Source RFP should be conducted by an independent party.

## 8. 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 IMP's willingness to engage in a robust discussion of the issues and give stakeholder feedback serious consideration. Reliable Energy would be happy to discuss the issues raised above further and to make its consulting experts available to IMP for in-depth discussions.

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[18] Cause 45403, Redacted Testimony of OUCC Witness Peter M. Boerger, Ph.D., September 8, 2020, pp. 5-6 (internal footnote omitted). Mr. Boerger further states: "If NIPSCO's solar resources had in its 2018 IRP been modeled to be [redacted] higher, other resource options would have been more attractive and NIPSCO's model may have selected a different resource mix. Thus, the higher solar costs NIPSCO is now seeing call into question whether the resources in this case, which are part of NIPSCO's Short-Term Action Plan, should be reconsidered."