March 24, 2022

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Electronically delivered

Re: Comments on NIPSCO's 2021 Integrated Resource Plan

Dear Director Borum, Chief Technical Advisor Pauley, and Assistant General Counsel Comeau,

Pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 Ind. Admin. Code 4-7, Citizens Action Coalition of Indiana ("CAC"), Earthjustice, and Vote Solar (collectively, "Commenters") hereby submit the attached report by Chelsea Hotaling and Anna Sommer with Energy Futures Group and Nicholas Miller with HickoryLedge on the 2021 Integrated Resource Plan ("IRP") submitted by the Northern Indiana Public Service Company ("NIPSCO"). Commenters have also attached relevant discovery responses, comments submitted by CAC during the IRP stakeholder process, and certain NIPSCO responses to CAC comments. These attachments do not reflect all informal discovery from CAC or the many conversations CAC had with NIPSCO throughout this process.

Our review of NIPSCO's 2021 IRP is organized to align with the IURC's IRP Rule. While we still have concerns about certain aspects of the IRP, NIPSCO deserves significant credit for the leadership it has taken to raise the bar for IRPs in Indiana. Specifically, NIPSCO routinely makes a good faith effort to take stakeholder feedback into account, conducts an all-source Request for Proposals in order to characterize new resources and uses that information as a primary data source in its modeling, and, finally, tries to tackle thorny questions such as the need for grid services through data driven analyses. This is clearly the result of the hard work of Alison Becker, Fred Gomos, and the rest of the NIPSCO IRP team, as well as Pat Augustine and his team at Charles River Associates.

We appreciate the opportunity to comment and engage in this public IRP stakeholder process and look forward to the issuance of and opportunity to comment on the Director's Draft Report. Please feel free to contact Jennifer Washburn, Counsel at Citizens Action Coalition, with any questions or concerns.

Respectfully,

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Report on Northern Indiana Public Service Company's 2021 IRP

Submitted to the IURC on March 24, 2022

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On behalf of Citizens Action Coalition of Indiana,
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Overview

The following comments on the 2021 Integrated Resource Plan ("IRP") submitted by Northern Indiana Public Service Company ("NIPSCO" or the "Company") were prepared by Chelsea Hotaling and Anna Sommer of Energy Futures Group and Nicholas Miller of HickoryLedge. These comments were prepared for Citizens Action Coalition of Indiana ("CAC"), Earthjustice, and Vote Solar ("Joint Commenters") pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") IRP Rule, 170 Ind. Admin. Code 4-7.

Our review of NIPSCO's 2021 IRP is organized to align with the IURC's IRP Rule. While we have concerns about the areas mentioned below, NIPSCO deserves significant credit for the leadership the Company has taken to raise the bar for IRPs in Indiana. Specifically, the Company routinely makes a good faith effort to take stakeholder feedback into account, conducts an all-source Request for Proposals ("RFP") in order to characterize new resources and uses that information as a primary data source in its modeling, and, finally, tries to tackle thorny questions such as the need for grid services through data driven analyses. This is clearly the result of the hard work of Alison Becker, Fred Gomos, and the rest of the NIPSCO IRP team, as well as Pat Augustine and his team at Charles River Associates.

Because NIPSCO takes the IRP process seriously, we, in turn, take seriously our role as stakeholders and see the value in participating in the process. We provide feedback as requested and in a timely fashion, and we closely review the materials provided by the Company. As useful as any stakeholder process can be, however, it cannot substitute for thorough review of the Company's IRP and its modeling files. Ideally, the stakeholder workshops will address the high level matters, e.g., the optimization approach, the scenarios and sensitivities developed, the major assumptions, etc. The review of the IRP and the modeling files, on the other hand, is the chance for stakeholders to understand the details of how these elements were combined to develop the IRP. It is not possible to discuss all the consequential details of IRP modeling even in multiple stakeholder workshops. Important information about market interactions, the manner in which constraints on resource selection were represented, how new resource costs were turned into model inputs, the choice of model settings and so on may have a material impact on the IRP results. We depend on the provision of transparent information and the discovery process to elicit the data that allows us to conduct a full review. In our view, the post-IRP review is not a pro-forma process in which we go through the motions; rather, it is central to creating an understanding of the IRP and the analytical data supporting it.

We look forward to continuing to work with NIPSCO to address the issues identified here to improve NIPSCO's next IRP and will be mindful of how these issues may impact subsequent IURC cases such as certificates of need.

Table 1, below, gives the Indiana IRP rule sections and provides the section in which those requirements will be addressed in detail. Our review of NIPSCO's 2021 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

- The Technical Appendix does not provide the information required under Indiana's IRP rule (Section 1);
- NIPSCO severely limited the resources that could be chosen during 2028 and 2029 despite the fact that major resource decisions were being contemplated during this time period in some portfolios (Section 3.2);
- NIPSCO did not explore adding portfolios of energy efficiency that would include all cost-effective energy efficiency identified in the Market Potential Study and exclude energy efficiency that was not cost-effective (Section 5.1);
- While it makes an important quantitative contribution to the manner in which reliability is considered, NIPSCO's reliability analysis, in several instances, either understated the ability of renewables and battery storage to provide grid services or overstated the ability of thermal generators to provide services comparable to renewables and battery storage (Section 7.2);
- It is unclear to what degree NIPSCO will reevaluate its decision to pursue Portfolio F as it goes through the process of acquiring the resources in that plan, but prudence dictates that it do so and maintain optionality as long as possible (Section 8).

Table 1. Summary of NIPSCO's Achievement of Indiana IRP Rule Requirements

IRP Rule Section	Description	Findings	Citation
Integrated Resource Plan Submission	The IRP submission should include a non-technical appendix and an IRP summary that communicates core IRP concepts and results to a nontechnical audience.	**Mostly**	See Section 1
Public Advisory Process	The IRP process should be developed and carried out to include stakeholder participation.	**Met**	See Section 2
Integrated Resource Plan Contents	The IRP should provide stakeholders with all of the information necessary to understand how the IRP modeling was performed.	**Mostly**	See Section 3
Energy and Demand Forecasts	The IRP should clearly explain how energy and demand forecasts were developed and used for the IRP.	**Mostly**	See Section 4
Description of Available Resources	The IRP must include important characteristics for existing and new resources included in the IRP.	**Mostly**	See Section 5
Selection of Resources	The IRP should describe the screening process used for evaluating future resources.	**Mostly**	See Section 6
Resource Portfolios	The IRP should discuss the preferred portfolio and discuss how alternative portfolios were developed to consider different scenarios.	**Mostly**	See Section 7
Short Term Action Plan	The IRP should discuss how the preferred portfolio will be implemented over the next five years.	**Partial**	See Section 8

1 Integrated Resource Plan Submission

Section 1 describes our assessment of NIPSCO's performance in meeting the requirements of 170 IAC 4-7-2 of the Indiana IRP Rule. Please see Table 2 below for our findings.

Table 2. Summary of NIPSCO's Achievement of Indiana IRP Rule at 170 IAC 4-7-2

IRP Rule	IRP Rule Description	Finding
4-7-2 (c)	Utility must submit electronically to the director or through an electronic filing system if requested by the director or through an electronic filing system if requested by the director, the following documents: (1) The IRP	**Met**
4-7-2 (c)	(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts; (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models (in electronic format); (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file	**Partial**
4-7-2 (c)	(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director and (B) A simplified discussion of the utility's resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	**Met**

NIPSCO's IRP consultant, Charles River Associates ("CRA"), used Energy Exemplar's Aurora model for capacity expansion and production cost modeling for this IRP. In a similar fashion to the 2018 IRP, CRA provided some modeling inputs and outputs in the Excel workbook labeled Confidential Appendix D. In order to ensure full transparency into the modeling inputs and outputs, it is our preference that stakeholders have access to the full set of input and output files. When Aurora is the tool used, gaining that access is especially difficult because of the inability to batch export input and output files. While Energy Exemplar offers either read-only or annual licenses for Aurora, that cost is not always within the budget of our clients. A number of states and utilities, including Arizona, South Carolina, New Mexico, Consumers, DTE, and I&M, have started to offer free modeling licenses to stakeholders for use in IRPs and related cases, but that was not available to us here. We did submit a request to NIPSCO to receive some of the Aurora input tables and output files. NIPSCO provided us with two workbooks containing portions of an Aurora input table and a few select output tables in response to this request. Although we appreciate NIPSCO and CRA providing the modeling inputs and some modeling outputs in response to our request, this still does not fulfill the requirement of IRP Rule 170 IAC 4-7-2. Specifically, the requirements for the Technical Appendix are that the technical appendix shall include at least the following:

(A) The utility's energy and demand forecasts and input data used to develop the forecasts,
(B) The characteristics and costs per unit of resources examined in the IRP;
(C) Input and output files from capacity planning models, in electric format;
(D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file.

The Energy Exemplar model manual can only be accessed through the Aurora interface. Each capacity expansion and production cost database, even within the same modeling platform, has its own setup for model inputs that may be different than other models. This means that, even if you have broad familiarity with the modeling tool used, the model documentation is invaluable for users who are trying to understand and interpret different inputs. When stakeholders do not have access to the model manual, it makes it challenging to be able to determine the full meaning behind some of the model inputs.

CAC appreciated NIPSCO's willingness to hold technical meetings with interested stakeholders and to listen to and incorporate stakeholder feedback into the IRP. However, we would recommend that NIPSCO consider a process of releasing and sharing information similar to the process used in Indianapolis Power & Light's ("IPL") most recent IRP, submitted in December 2019. IPL used a file sharing site to share information at several points throughout the IRP process. Information was only shared with those stakeholders that signed a nondisclosure agreement ("NDA") with IPL. IPL had a schedule of release dates for when they provided stakeholders with capital cost information, resource constraints, key modeling inputs, and then modeling results. We believe that this data sharing approach helped to facilitate stakeholder involvement, expectations, and input throughout the process and ultimately increased stakeholder engagement. IPL's approach is much closer to satisfying 170 IAC 4-7-2(c) which requires each utility to provide input and output files in electronic format, as well as include "documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP".[1]

We cannot overstate the importance of transparency in IRPs. It is the foundation of public participation, which, in turn, is foundational to the Commission's ability to render decisions based on a comprehensive record. While we appreciate the work NIPSCO and CRA did to provide us with modeling inputs and outputs and to otherwise collaborate and meet with us, we recommend the above process to achieve the full transparency required by Indiana's IRP rule.

[1] 170 IAC 4-7-2.6 also requires a utility to discuss modeling methods and modeling inputs as part of the public advisory process. *See also* Order, I/M/O Submission by Hoosier Energy Rural Elec. Coop., Inc. of Its 2017 Integrated Res. Plan, Cause No. 45058, 2018 WL 2329333, at *2 (May 16, 2018) (acknowledging that 170 IAC 4-7-2(c)(2) requires disclosure of market price assumptions, production statistics for generating assets, and model data).

2 Public Advisory Process

Section 2 describes our assessment of NIPSCO's performance in meeting the requirements of 170 IAC 4-7-2.6 of the Indiana IRP Rule. Please see Table 3 below for our findings.

Table 3. Summary of NIPSCO's Achievement of Indiana IRP Rule at 170 IAC 4-7-2.6

IRP Rule	IRP Rule Description	Finding
4-7-2.6 (b)	The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	**Met**
4-7-2.6 (c)	The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by: (1) the interested parties; (2) the OUCC; (3) the commission staff.	**Met**
4-7-2.6 (e)	The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process, (B) The utility's load forecast, (C) Evaluation of existing resources, (D) Evaluation of supply-side and demand-side resource alternatives, (E) Modeling methods, (F) Modeling inputs, (G) Treatment of risk and uncertainty, (H) Discussion seeking input on its candidate resource portfolios, (I) The utility's scenarios and sensitivities, (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	**Met**
4-7-2.6 (e)	(2) The utility may hold additional meetings.	**Met**
4-7-2.6 (e)	(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	**Met**
4-7-2.6 (e)	(4) The utility or its designee shall: (A) chair the participation process; (B) schedule meetings; (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and (D) develop and publish to its website meeting minutes within fifteen (15) calendar days following the meeting	**Met**
4-7-2.6 (e)	(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.	**Met**
4-7-2.6 (e)	(6) The utility shall take reasonable steps to notify: (A) its customers; (B) the commission; (C) interested parties; and (D) the OUCC	**Met**

For this IRP, NIPSCO held five public stakeholder meetings and one technical webinar to discuss its reliability assessment. We appreciate the time that NIPSCO took to ensure that stakeholders had the opportunity to meet with NIPSCO and CRA for technical meetings and their willingness to incorporate stakeholder feedback into this IRP.

3 Integrated Resource Plan Contents

Section 3 describes our assessment of NIPSCO's performance in meeting the requirements of 170 IAC 4-7-4 of the Indiana IRP Rule. Please see Table 4 below for our findings.

Table 4. Summary of NIPSCO's Achievement of Indiana IRP Rule at 170 IAC 4-7-4

IRP Rule	IRP Rule Description	Finding
4-7-4 (1)	At least a twenty (20) year future period for predicted or forecasted analyses.	**Met**
4-7-4 (2)	An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	**Not Met**
4-7-4 (3)	At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	**Met**
4-7-4 (4)	A description of the utility's existing resources in compliance with section 6(a) of this rule.	**Met**
4-7-4 (5)	A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	**Met**
4-7-4 (6)	A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	**Mostly**
4-7-4 (7)	The resource screening analysis and resource summary table required by section 7 of this rule.	**Mostly**
4-7-4 (8)	A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	**Met**
4-7-4 (9)	A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	**Mostly**
4-7-4 (10)	A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	**Mostly**
4-7-4 (11)	A discussion of the: (A) inputs; (B) methods; and (C) definitions.	**Met**
4-7-4 (12)	Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	**Met**
4-7-4 (13)	A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	**Not Met**
4-7-4 (14)	The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility; (B) Load research developed in conjunction with another utility; (C) Load research developed by another utility and modified to meet the characteristics of that utility; (D) Engineering estimates; and (E) Load data developed by a non-utility source.	**Not Met**
4-7-4 (15)	A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	**Partial**
4-7-4 (16)	A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	**Met**
4-7-4 (17)	A discussion of the designated contemporary issues designated, if required by section 2.7(e).	**Met**
4-7-4 (18)	A discussion of distributed generation within the service territory and the potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	**Mostly**

4-7-4 (19)	For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	**Met**
4-7-4 (20)	A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development	**Met**
4-7-4 (21)	A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	**Met**
4-7-4 (22)	A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	**Mostly**
4-7-4 (23)	A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	**Met**
4-7-4 (24)	A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	**Met**
4-7-4 (25)	A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A base case scenario need not align with the utility's preferred resource portfolio.	**Met**
4-7-4 (26)	A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	**Met**
4-7-4 (27)	A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis; (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC); and (C) Reliability criteria for transmission planning as well as the assessment practice used.	**Met**
4-7-4 (28)	A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use and (B)The utility's effort to develop and improve the methodology and inputs.	**Mostly**
4-7-4 (29)	An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement; (B) The avoided transmission capacity cost; (C) The avoided distribution capacity cost; and (D) The avoided operating cost.	**Partial**
4-7-4 (30)	A summary of the utility's most recent public advisory process, including: (A) Key issues discussed and (B) How the utility responded to the issues.	**Met**
4-7-4 (31)	A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	**Met**

3.1 MISO SEASONAL PLANNING CONSTRUCT

MISO has been working on the redesign of its resource adequacy ("RA") construct for several years now. In November 2021, it filed at the Federal Energy Regulatory Commission ("FERC") in Docket No. ER22-495 for seasonal-based changes to both the RA construct and its accreditation methodology for thermal generators. On March 9, 2022, FERC issued a deficiency letter to MISO and asked a detailed set of questions about key aspects of the proposed changes such as the use of data from different seasons to accredit resources, why MISO's thermal accreditation methodology would do a better job of determining unit performance than its current approach, and why MISO is proposing a different accreditation method for different technology types. MISO has thirty days to respond, but the future of these proposed changes is very much up in the air.

While presentations at MISO Resource Adequacy Subcommittee meetings suggest that there will be a differential in seasonal reserve margin requirement rather than remaining static across all seasons, NIPSCO performed modeling that first optimized portfolios to a winter reserve margin constraint of 9.4%, then optimized portfolios to the summer reserve margin constraint of 9.4% to determine whether each portfolio could meet both a winter and summer reserve margin. As NIPSCO said, "For winter planning reserve margin purposes, NIPSCO also assumed a 9.4% target, although formal rules and seasonal reserve margin standards have yet to be defined for MISO's forthcoming seasonal resource adequacy construct."[2] As the proposed seasonal RA construct is underway, it has not been determined what exactly the winter reserve margin requirement would be, except that there will likely be a differential across all seasons.

In previous comments for Indiana utility IRPs, we have recommended against a base case assumption of a monthly or seasonal RA construct because it does not meet the criteria of the IRP Rule at 170 IAC 4-7-4(25)(D). The likelihood of changes to MISO's RA construct have certainly increased since then though the details of those changes remain uncertain. We continue to believe it is good best practice to explore differing RA assumptions and to model the proposed construct as closely as possible. NIPSCO largely did that in using three categories of what it called "dispatchability" which essentially serve as different interpretations of resource adequacy requirements. Those dispatchability categories were: "portfolios that meet only the existing summer reserve margin requirements", "portfolios that meet both winter and summer reserve margin requirements over time", and " '[e] nhanced' reserve margin portfolios that more fully rely on local resources with longer energy duration capabilities".[3]

NIPSCO also did not attempt to represent MISO's proposed thermal accreditation methodology – seasonal accreditation capacity ("SAC") – in its modeling, however, after Michigan City 12 is retired in 2026 or 2028, the only major thermal unit on NIPSCO's system will be the CCGT facility, Sugar Creek. Because the proposed changes in thermal accreditation will have the largest deleterious impact on poorly performing thermal units, we were much less concerned that by modeling a static seasonal planning reserve margin and *not* using MISO's proposed SAC

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[2] NIPSCO 2021 IRP, page 20.
[3] NIPSCO 2021 IRP, page 222.

methodology that the model would retain poorly performing thermal units since their contribution to the winter reserve margin would have been overstated.

For all of these reasons, we are much more comfortable with NIPSCO's resource adequacy approach than we have been with other Indiana utilities with much more thermal heavy systems.

3.2 NEW RESOURCES

3.2.1 Resource Selection Years

Based on our understanding of NIPSCO's modeling process for this IRP, the first modeling step involved performing capacity expansion modeling across different retirement dates for Michigan City Unit 12 and the Schahfer units. In this capacity expansion modeling for the retirement analysis, NIPSCO allowed the model to optimize between a mix of resources that represented bids from the RFP, generic resources, a Sugar Creek uprate project, new CTs, distributed energy resources ("DERs"), and energy efficiency and demand response bundles. However, NIPSCO did not allow the generic solar and battery storage resources to be selected until 2030 and did not model generic wind at all, leaving at least two years in which very limited resources could be selected by the model." While NIPSCO did allow two RFP tranches of storage to be selected in 2027, the other RFP resources were just available for selection between 2024 and 2026. That leaves the following as the only other selectable resources between 2027 and 2029: the Sugar Creek uprate, the energy efficiency bundles, and the DER resources. NIPSCO's second modeling step involved taking the retirement dates that were determined in that first step of modeling and developing portfolios of resources that fit the different modeling themes, meaning those portfolios were not solely determined by a capacity expansion model.

When we asked NIPSCO about the rationale for limiting the years in which new resources were available for selection within the first modeling step, i.e. the capacity expansion modeling, NIPSCO said:

> *From a modeling perspective, RFP tranches Storage P2 and Storage A2 were available for selection in 2027, reflecting the fact that the online dates offered for RFP resources in these tranches implied that the 2027/28 MISO planning year would be the first year capacity would be accredited. The Solar + Storage P2 tranche was available for selection in 2023, given the online dates offered for RFP resources in that tranche. All other RFP resources were allowed to be selected between 2024 and 2026.*[4]
>
> *In addition to the tranches noted in NIPSCO's response to subpart b. of this request, the Sugar Creek Uprate and distributed energy resources were also available during this time period, as discussed in subpart d.*[5]

[4] NIPSCO response to CAC Informal Discovery Request 1-011 b.
[5] NIPSCO response to CAC Informal Discovery Request 1-011 c.

> *Aurora was not allowed to select any new resources between 2027 and 2029 aside from those referenced in NIPSCO's response to sub-part c. The modeling framework was set up this way to evaluate actual RFP projects that could be used to meet capacity needs that may arise through 2026 with the potential retirement of Michigan City Unit 12 and Schahfer Units 16AB, rather than allow for more speculative resource costs in the subsequent years to impact resource selection and revenue requirement accounting.*[6]

As we have stated in these comments and in prior comments on other IRPs, when a capacity deficit is anticipated, it is good practice to use an RFP to characterize the cost of available resources to meet that deficit. That remains true, but it is also not sufficient. An all-source RFP is not a singular source of information to characterize resource options, because it does not normally result in proposals that are available more than a few years out. It is not a mechanism likely to result in significant (or even any) amounts of demand-side resources, and typically proposals using existing interconnection rights such as utility self-build proposals will not respond or are even ineligible. We are skeptical that an RFP issued in 2021 would capture the likely universe of proposals that would be available to NIPSCO six or more years down the road. We cannot say what the impact would be on the optimization results if generic resources had been made available to the model from 2027 to 2040 since we did not have access to Aurora to conduct our own runs. We believe it is good practice to allow resources to be selected over the entirety of the planning period, especially during timeframes when key decisions on whether to retire units are central to the capacity expansion modeling.

3.2.2 Generic Solar Capital Cost

NIPSCO included the RFP tranches to represent the RFP bids and then allowed the model to select generic renewable and storage resources starting in 2030. Our review of the generic solar costs indicates that NIPSCO is overestimating the costs of these resources, apparently stemming from inflationary concerns that occurred with projects due to supply chain issues. In response to CAC Informal Discovery Request 1-009, NIPSCO said:

> *The capital cost projections for solar and storage resources were based on information received via the RFP, Charles River Associates, Inc.'s ("CRA's") recent project experience, and the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("NREL ATB") 2020 mid decline curves. For example, for solar resources, the average cost from RFP projects was approximately $1,450/kW, and CRA has witnessed recent inflationary pressures driving costs for mid-decade projects even higher. Thus, generic resources were priced at this level in 2030, following the NREL trajectory thereafter.*[7]

[6] NIPSCO response to CAC Informal Discovery Request 1-011 d.
[7] NIPSCO response to CAC Informal Discovery Request 1-009.

Figure 1 shows the comparison of NIPSCO's generic resource cost compared to the NREL's 2021 ATB for solar resources. The cost difference between NIPSCO's solar assumption and the 2021 ATB solar costs is about 43%. We understand that the global pandemic has led to supply chain issues and inflationary pressures, but NIPSCO's costs assumptions seem to single out solar projects exclusively. We are concerned that this inflationary pressure is being applied in a discriminatory fashion if it is not being equitable applied to all resource types. For instance, inflation in the labor market would apply to any project regardless of whether it is a renewable, storage, or thermal project.

In addition, the long-term impact of the current supply chain and inflationary costs are unknown, especially if one is looking at projects implemented in the late 2020s and early 2030s. If these cost increases do continue to persist into the late 2020s and 2030s timeframe, then cost increases need to be evaluated across all resource types and not just one technology.

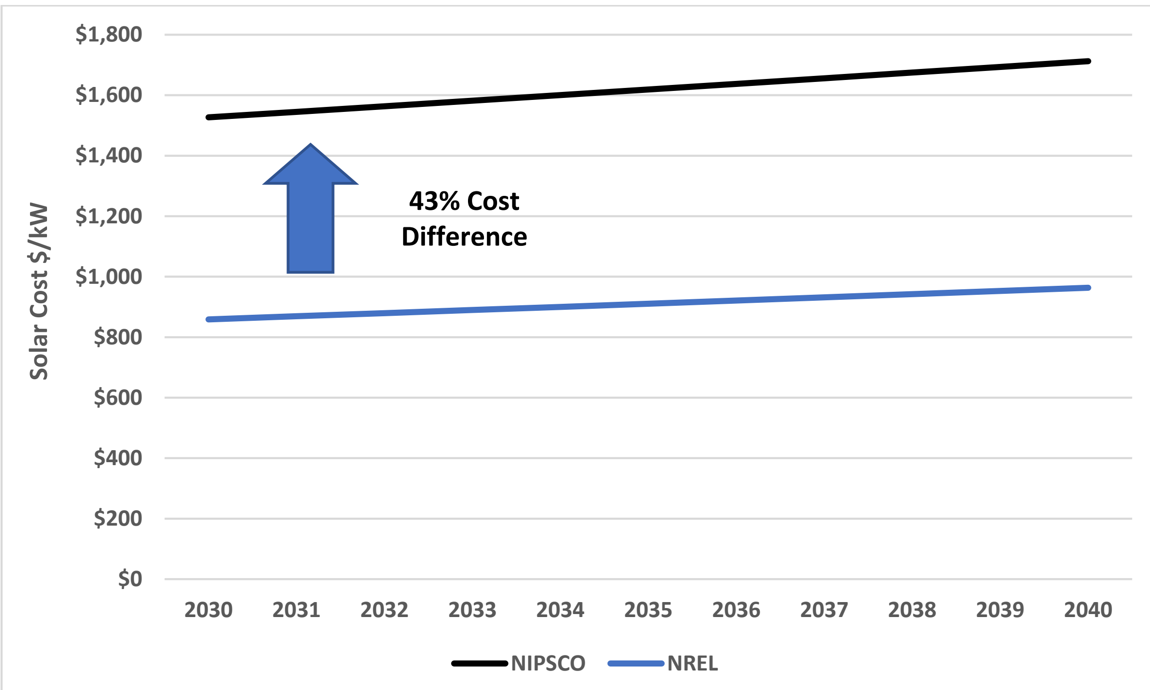

Figure 1. Generic Solar Cost Comparison ($/kW)[8]

3.2.3 Investment Tax Credit

We appreciate NIPSCO's thoughtful treatment of the Investment Tax Credit ("ITC") for new solar resources. Under the Internal Revenue Code, the ITC is required to be normalized, meaning ITC benefits are spread across the life of the solar asset. However, NIPSCO assumed a workaround by entering into a tax equity partnership, as it has done previously, that would allow

[8] NIPSCO solar generic cost information from Confidential Appendix D which NIPSCO has agreed to make public.

for the ITC to be credited in the first year of the project instead of normalized over the project life. In the IRP, NIPSCO said:

> *In this arrangement, NIPSCO and a tax equity investor would form a partnership to develop a renewable energy project. The tax equity investor would invest to obtain a specified internal rate of return through the receipt of tax benefits in the form of depreciation, tax credits, and cash for a specified timeframe. NIPSCO would place its portion of the investment, which would be a fraction of the total cost, in rate base.*[9]

3.3 SUB-HOURLY MODELING WITH ANCILLARY SERVICES

Since the modeling performed within Aurora is based on day-ahead energy markets, NIPSCO performed an analysis outside of Aurora through CRA's proprietary Energy Storage Operation ("ESOP") model to approximate incremental value streams for ancillary services (energy, frequency regulation, and spinning reserves) for battery storage, solar paired with battery storage, and natural gas peaking resources. This analysis was performed using historical price data and CRA's estimation of price trajectories based on historical relationships between day-ahead energy, real-time energy, and ancillary services prices, which were then applied to the day-ahead energy price forecasts that were created for the IRP. The analysis was performed across the years of 2025, 2030, 2035, and 2040. Figure 2 shows the ancillary services value ($/kW-Year) that NIPSCO calculated through the ESOP model for storage, solar plus storage, and gas peaking resources. The value from storage resources is about three times the value for gas peaking resources.

It is challenging to appropriately characterize and capture the value streams for ancillary services in capacity expansion modeling. We appreciate NIPSCO taking this additional step to try to reflect the value of all resources, but we recognize that there are still challenges with this approach. Similar to our recommendation to credit DER benefits as a reduction in the cost of those resources, a similar approach is possible here. Had the ancillary service value for storage, in particular, been credited as a reduction in cost, it might have influenced the identification of initial expansion plans and resulted in more storage than what was selected. We look forward to continuing to work with NIPSCO to think through the best approach for modeling and capturing the value of ancillary services.

[9] NIPSCO 2021 IRP, page 92.

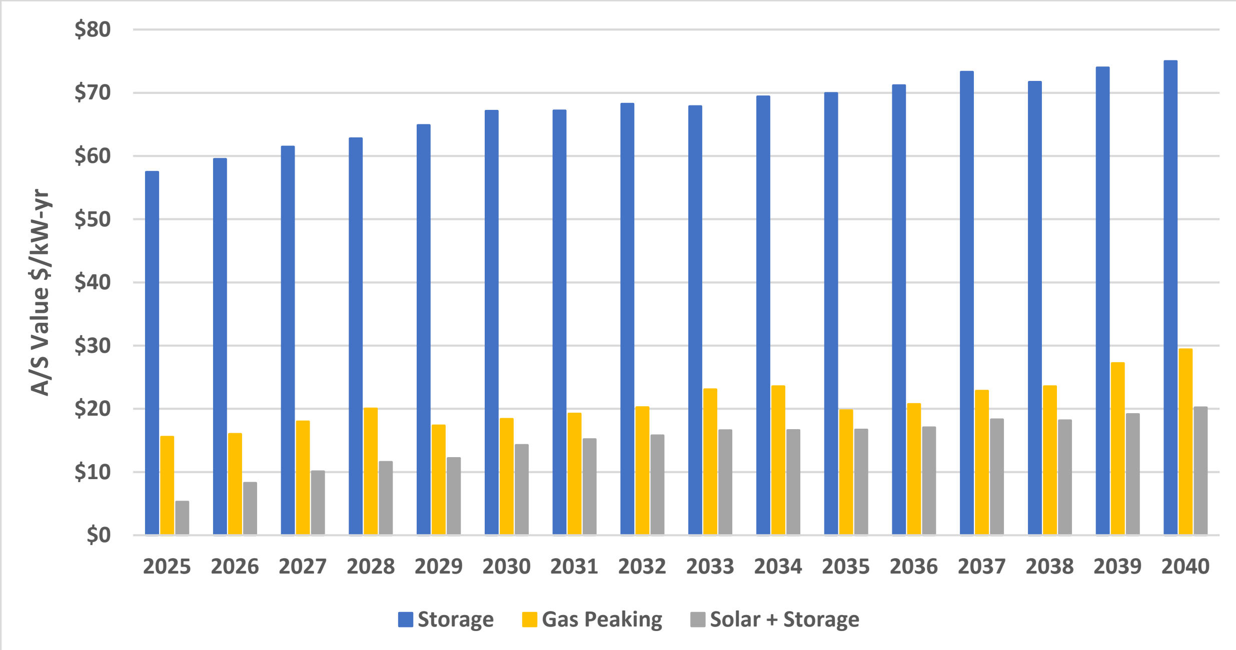

Figure 2. Ancillary Service Value $/kW-Year[10]

3.4 AVOIDED COST CALCULATION

Section 4-7-4 (29) of the IRP Rule requires the following components to be included in the avoided cost calculation:

(A) Avoided generating capacity (adjusted for T&D losses and reserve margin requirement)
(B) Avoided transmission capacity cost
(C) Avoided distribution capacity cost
(D) Avoided operating cost
  (i) Fuel cost;
  (ii) Plant operation and maintenance costs;
  (iii) Spinning reserve;
  (iv) Emission allowances;
  (v) Environmental compliance costs; and
  (vi) Transmission and distribution operation and maintenance costs.

The IRP does not explicitly contain the avoided costs required by the IRP rule. Appendix B, which contains the DSM market potential study, says in a footnote that "avoided energy costs are not included in his study because of the low assumed annual hours of dispatch (24 hours per year) and the lack of time-differentiation in the avoided energy costs used for this study (i.e., the on-peak and off-peak avoided cost per kWh provided by NIPSCO were the same)." That does

[10] Provided in NIPSCO response to CAC Informal Request 1-021, Attachment A.

not, however, mean that an avoided energy/operating cost does not exist and as such, it should be included here.

3.5 MODELING DISTRIBUTED ENERGY RESOURCES

For this IRP, NIPSCO evaluated DERs as a supply side resource option that could be economically selected by Aurora in the capacity expansion model. NIPSCO assessed near-term system upgrade requirements across the distribution system that could be potential locations for deferring investments through the implementation of DER. NIPSCO identified 21 possible sites that will need capacity improvement investments in the next five years and estimated the distribution upgrade project costs for those locations in addition to the years these projects could be deferred due to DERs. This allowed NIPSCO to develop a Net Present Value ("NPV") for each location which was then subtracted from the capital cost of the resource options. Table 5 below shows the DER resources that were modeled in Aurora.

Table 5. DER Bundles[11]

Deferral Cost Bundle	Resource	Battery Storage MW	Solar MW	Range of Potential NPV of Deferred Investment ($/kW)
High	Solar + Battery	7.0	2.7	**700 – 900**
Mid	Solar + Battery	7.0	9.1	**200 – 300**
Low	Solar + Battery	2.0	2.7	**10 – 100**

NIPSCO has taken an important analytical step towards being able to fully incorporate DERs as a supply side resource option in capacity optimization modeling. NIPSCO's optimization analysis found that approximately 10 MWs of DERs were consistently selected by the model and included them in the replacement portfolios.

[11] NIPSCO 2021 IRP, Figure 4-16, page 96.

4 Energy and Demand Forecasts

Section 4 describes our assessment of NIPSCO's performance in meeting the requirements of 170 IAC 4-7-5 of the Indiana IRP Rule. Please see Table 6 below for our findings.

Table 6. Summary of NIPSCO's Achievement of Indiana IRP Rule at 170 IAC 4-7-5

IRP Rule	IRP Rule Description	Findings
4-7-5 (a)	The analysis of historical and forecasted levels of peak demand and energy usage must include the following:(1) Historical load shapes, including the following: (A) Annual load shapes; (B) Seasonal load shapes; (C) Monthly load shapes; (D) Selected weekly load shapes; and (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	**Not Met**
4-7-5 (a)	(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	**Met**
4-7-5 (a)	(3) Actual and weather normalized energy and demand levels.	**Not Met**
4-7-5 (a)	(4) A discussion of methods and processes used to weather normalize.	**Not Met**
4-7-5 (a)	(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	**Met**
4-7-5 (a)	(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system; (B) Customer classes, rate classes, or both; and (C) Firm wholesale power sales.	**Not Met**
4-7-5 (a)	(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	**Partial**
4-7-5 (a)	(8) Justification for the selected forecasting methodology.	**Met**
4-7-5 (a)	(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	**Not Met**
4-7-5 (a)	(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in subdivision 4(14) of this rule.	**Met**
4-7-5 (b)	To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable peak demand and energy use forecasts.	**Met**
4-7-5 (c)	In determining the peak demand and energy usage forecast to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider likely based on alternative assumptions such as (1) Rate of change in population; (2) Economic activity; (3) Fuel prices, including competition; (4) Price elasticity; (5) Penetration of new technology; (6) Demographic changes in population; (7) Customer usage; (8) Changes in technology; (9) Behavioral factors affecting customer consumption; (10) State and federal energy policies; and (11) State and federal environmental policies.	**Mostly**

4.1 NIPSCO LOAD FORECAST

CRA used regression estimation to develop the customer count and customer sales forecasts for the IRP. The results of the load forecast indicate that the summer peak load is projected to decline at a compound annual growth rate ("CAGR") of 0.2%, and winter peak load is projected to increase at a CAGR of 0.2% over the next twenty years.[12] Table 7 below shows the CAGR for the customer count, sales, summer peak, and winter peak forecasts by customer class.

Table 7. 2021 to 2040 CAGR by Customer Class[13,14,15]

Customer Class	Customer Count	Sales	Summer Peak	Winter Peak
Residential	0.5%	0.2%	-0.1%	0.5%
Commercial	0.8%	0.4%	0.2%	0.6%
Small Industrial	0.3%	-0.1%	-0.2%	-0.2%
Large Industrial, non-831	-	-0.4%	-1.3%	-1.4%
Large Industrial 831 T1	-	0.0%	0.0%	0.3%

As Table 7 indicates, the largest growth in customer count, sales, summer peak, and winter peak is forecasted to come from the commercial customer class, while the large industrial, non-831 class is expected to have the largest decrease in sales, summer peak, and winter peak.

4.2 LOAD FORECAST SCENARIOS

In addition to the reference case load forecast, NIPSCO also developed and modeled three alternative forecasts, which included the Status Quo Extended, Aggressive Environmental Regulation, and Economy-Wide Decarbonization. The Status Quo Extended forecast evaluates the potential for additional loss of industrial load down to 70 MW. The Economy-Wide Decarbonization forecast used the information from the MISO MTEP 2021 electrification study to create LRZ 6 projections for NIPSCO's service territory. Figure 3 shows the load forecast across the scenarios, and Table 8 shows the summer and winter peak CAGR for each scenario.

[12] NIPSCO 2021 IRP, page 25.
[13] NIPSCO 2021 IRP, page 25.
[14] NIPSCO 2021 IRP, Figure 3-5, page 32.
[15] NIPSCO 2021 IRP, Figure 3-7, page 34.

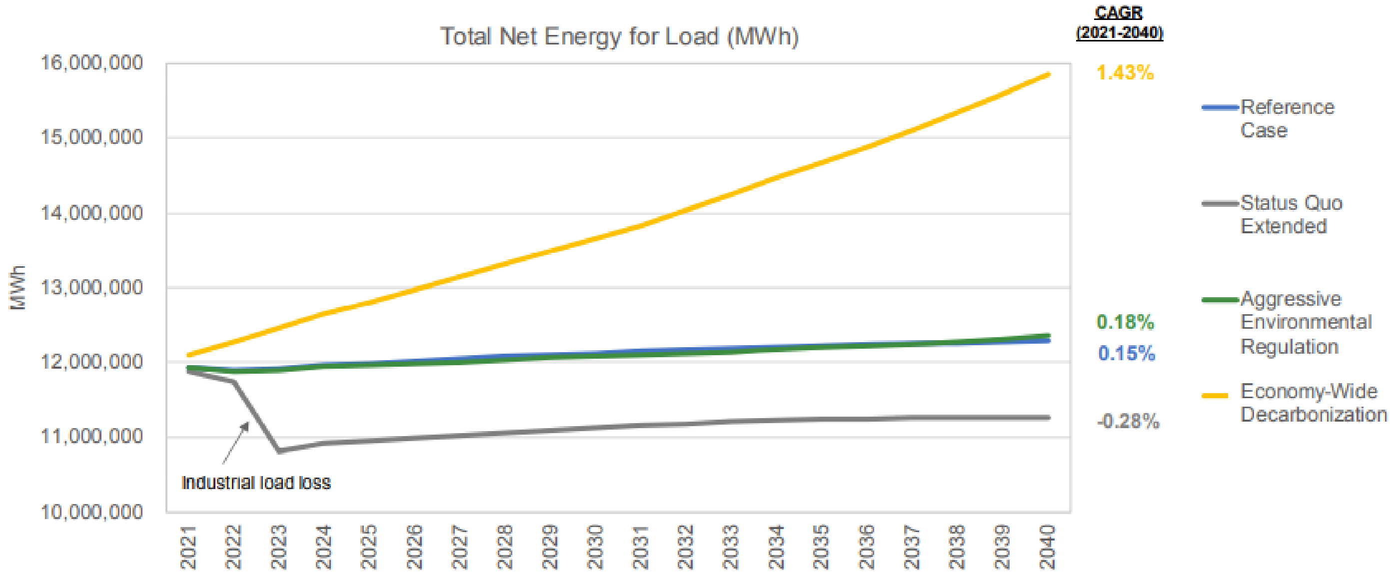

Figure 3. NIPSCO Load Forecast Scenarios[16]

The Economy-Wide Decarbonization scenario has the largest load CAGR at 1.43%, while the Status Quo Extended scenario has the lowest CAGR at -0.28% between 2021 and 2040. The Aggressive Environmental Regulation scenario is at a 0.18% CAGR, which is only 0.03% higher than the Reference Case scenario. Table 8 shows the summer and winter peak CAGRs for the different scenarios. As expected, the Economy-Wide Decarbonization scenario has the highest growth in summer and winter peak, while the Status Quo Extended scenario has the lowest growth in summer and winter peak.

Table 8. Summer and Winter Peak CAGR for Load Forecast Scenarios[17]

Scenario	Summer Peak	Winter Peak
Reference	-0.16%	0.21%
Status Quo Extended	-0.40%	-0.12%
Aggressive Environmental Regulation	-0.30%	0.03%
Economy-Wide Decarbonization	0.62%	2.11%

4.3 ACCOUNTING FOR DSM IN THE LOAD FORECAST

NIPSCO's approach for incorporating energy efficiency into its load forecast is that the energy and peak load forecast includes "[d]evelopment of baseline customer count and energy forecasts for each NIPSCO customer rate class, excluding historical DSM, and development of accompanying peak load forecasts using the energy forecast and load factors by customer rate class.[18] NIPSCO then makes "[a]djustments to the load forecast to incorporate existing and planned known DSM programs."[19]

Based on the description in the IRP, it appears that NIPSCO adds historical DSM into its baseline energy forecast to develop a "No DSM" load forecast and then makes adjustments to incorporate known DSM programs. This method seems to align with one of the three methods for incorporating DSM into the load forecast from an Itron whitepaper.[20] The two other methods suggested by Itron include the DSM variable and the DSM trend methods. The DSM variable method involves including historical DSM as a right-hand side variable in the load forecast to represent the cumulative historical impact of past programs. The DSM trend method assumes that historical DSM and DSM trends are embedded in the sales data and that the historical DSM savings trends will continue for the forecast at around the same rate. We appreciate that NIPSCO went to the extra effort to develop a "No DSM" forecast, which we consider critical to representing load and explicitly modeling energy efficiency.

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[18] NIPSCO 2021 IRP, page 26.
[19] NIPSCO 2021 IRP, page 26.
[20] Incorporating DSM into the Load Forecast. Itron. Retrieved from https://www.itron.com/-/media/feature/products/documents/white-paper/incorporating-dsm-into-the-load-forecast.pdf

5 Description of Available Resources

Section 5 describes our assessment of NIPSCO's performance in meeting the requirements of 170 IAC 4-7-6 of the Indiana IRP Rule. Please see Table 9 below for our findings.

Table 9. Summary of NIPSCO's Achievement of Indiana IRP Rule at 170 IAC 4-7-6

IRP Rule	IRP Rule Description	Findings
4-7-6 (a)	In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the 20 year planning period being evaluated: (1) The net and gross dependable generating capacity of the system and each generating unit.	**Met**
4-7-6 (a)	(2) The expected changes to existing generating capacity, including the following: (A) Retirements; (B) Deratings; (C) Plant life extensions; (D) Repowering; and (E) Refurbishment.	**Met**
4-7-6 (a)	(3) A fuel price forecast by generating unit.	**Met**
4-7-6 (a)	(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; (D) subsequent disposal; and (E) water consumption and discharge at each existing fossil fueled generating unit.	**Met**
4-7-6 (a)	(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	**Partial**
4-7-6 (a)	(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	**Met**
4-7-6 (b)	In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	**Partial**
4-7-6 (b)	(2) For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters; (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined; (C) The customer class or end-use, or both, affected by the demand-side resource; (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings; (E) The estimated impact of a demand side resource on the utility's load, generating capacity, and transmission and distribution requirements; (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	**Mostly**
4-7-6 (b)	(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered; (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost; (C) A description of significant environmental effects.	**Met**

4-7-6 (b)	(4) In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource; (B) A description of the timing, types of expansion, and alternative options considered; (C) The approximate cost of expected expansion and alteration of the transmission network; (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources; (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	**Mostly**

5.1 ENERGY EFFICIENCY

We appreciate the collaborative approach NIPSCO has taken by seeking and incorporating stakeholder feedback from the development of the Market Potential Study ("MPS") to determine how to model energy efficiency in Aurora. For this IRP, NIPSCO implemented what we would consider best practices around accounting for transmission and distribution ("T&D") benefits of the energy efficiency bundles and levelizing the bundle costs over the lifetime of savings. We appreciate the open dialogue we were able to have with NIPSCO and its MPS vendor, GDS Associates ("GDS"), about alternative ways to model energy efficiency for this IRP. As we continue to work on IRPs, our thinking on approaches to modeling energy efficiency for IRPs has evolved. For NIPSCO's IRP, we suggested that NIPSCO model the two levels of potential identified by the MPS, by customer sector, to see which level is selected by the capacity expansion model.

We look forward to continuing to work with NIPSCO and its consultants in a collaborative fashion related to the modeling of energy efficiency in NIPSCO's next IRP.

5.1.1 Modeling Realistic Achievable and Maximum Achievable Potential

For this IRP, NIPSCO modeled two levels of potential for residential and commercial & industrial ("C&I") energy efficiency measures, which was the realistic achievable potential ("RAP") and the maximum achievable potential ("MAP"). Residential savings were further divided between Tier 1, or low/mid cost measures, and Tier 2, or high-cost measures while income qualified programs were separately added to each portfolio since they do not need to pass traditional cost-effectiveness screening. NIPSCO found the following to be cost-effective in the optimization analysis: RAP Tier 1 residential energy efficiency for 2024-2029, 2030-2035, and 2036-2041; commercial and industrial energy efficiency for 2024-2029, 2030-2035, and 2036-2041; and residential DR rate programs after 2030.

5.1.2 Modeling Runs with Maximum Achievable Potential

NIPSCO evaluated the impact of including the MAP level of energy efficiency for Portfolio F in the replacement analysis step. NIPSCO reported that, "This was done by effectively 'forcing in' the same residential and commercial/industrial energy efficiency programs identified in the original optimization analysis, but at the MAP level instead of at the RAP level."[21] Based on the IRP narrative, it appears that NIPSCO forced in the higher MAP level of energy efficiency, but did not reoptimize Portfolio F to see how the capacity expansion plan changes with the MAP level of energy efficiency. In the IRP, NIPSCO said, "The impact of reduced energy requirements was evaluated through a re-dispatch of the portfolios in the Aurora portfolio model, while 100 MW of future storage additions in the 2030s were removed to reflect the reduced capacity obligation."[22] We appreciate NIPSCO taking the steps to evaluate the MAP level of energy efficiency, but we would recommend that evaluating different levels of energy efficiency requires reoptimizing the capacity expansion plan to see how the resource mix changes with the different level of energy efficiency. This allows one to understand the change in the impact to the Net Present Value of Revenue Requirements ("NPVRR") from moving from the RAP to the MAP level.

In addition to looking at additional levels of energy efficiency under reoptimized portfolios, we also would recommend that NIPSCO evaluate the residential MAP, the C&I MAP savings, and then mixed combinations, i.e., residential RAP and C&I MAP. The potential cost-effectiveness of this combination is supported by the results of the Utility Cost Test ("UCT") in the IRP. Table 10 shows the UCT results for the MAP and RAP level of savings. This indicates that there was a positive UCT, or positive net benefits, for the C&I MAP level of energy efficiency. Because the C&I MAP is not intertwined with the implementation of the much more expensive residential MAP, it would have made sense to at least have modeled the C&I MAP along with the residential RAP savings.

Table 10. UCT Benefit Cost Analysis Results for C&I[23]

Achievable Potential	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
RAP - C&I	$821,153,048	$170,179,466	$650,973,582	4.8
RAP - Residential	$470,746,985	$273,081,219	$197,665,766	1.72
MAP - C&I	$1,044,498,910	$647,750,938	$396,747,972	1.6
MAP - Residential	$841,694,153	$958,024,364	($116,330,211)	.88

[21] NIPSCO 2021 IRP, page 236.
[22] NIPSCO 2021 IRP, page 236.
[23] NIPSCO 2021 IRP, Table 5-13, page 131.

Table 10 also shows that C&I MAP savings were actually slightly more cost-effective than the residential RAP portfolio, which the model picked. The residential MAP portfolio was not cost-effective which suggests, though it is not definitive on this point, that this portfolio would not be cost-effective from an IRP perspective either.

In CenterPoint's 2019/2020 IRP, Aurora typically selected 0.75% incremental energy efficiency but when CenterPoint included a sensitivity with a 1.25% energy efficiency level in the near-term, the overall cost impact to the portfolio was about 0.15%.[24] CenterPoint then decided to move forward with the 1.25% level of energy efficiency for the first three years of the plan since the cost impact was minimal and such could be the case here as well. Indeed, it is not possible to definitely conclude the direction of the impact on net present value from inclusion of the C&I MAP savings because the costs it would avoid are not necessarily the same avoided costs as those used in the MPS to determine these UCT ratios. In fact, they can be quite different because the level of energy efficiency in a capacity expansion plan can have important impacts on deferring or avoiding new generation. The avoided costs used in an MPS do not typically capture this dynamic and are assumed to vary over time because of inflation, the start of carbon pricing, and other trends outside the utility's own resource portfolio.

5.1.3 Line Losses

In several IRP comments, we have recommended that utilities use marginal rather than average line losses to adjust energy efficiency savings from the meter to the generator for modeling in IRPs. The rationale for this recommendation is that efficiency savings occur at the margin, and therefore the avoided line losses are higher than the system-wide average line loss value. In response to this recommendation, NIPSCO reported that:

> *NIPSCO provided the GDS Team with both average and peak line loss factors. The GDS Team used the peak LLFs to adjust savings at the meter to the generator-level. NIPSCO has not conduced a marginal versus average line loss study, but the use of the peak LLF for DSM impacts is used as a proxy for the marginal LLF. The peak residential line loss used in the analysis was 4.11%. The peak commercial and industrial LLF were 3.76% and 2.41% respectively.*[25]

We greatly appreciate that NIPSCO provided GDS with the peak rather than average line losses for use in translating savings from the meter to the generator; however, the peak line losses reported in the IRP seem to be smaller than anticipated for peak losses. We raised this question in our first set of comments and never received a response. We encourage NIPSCO to engage in a marginal line loss study to be able to represent those line losses when converting savings from the meter to the generator.

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[24] CenterPoint 2019/2020 IRP, page 102.
[25] NIPSCO 2021 IRP, page 122.

6 Selection of Resources

Section 6 describes our assessment of NIPSCO's performance in meeting the requirements of 170 IAC 4-7-7 of the Indiana IRP Rule. Please see Table 11 below for our findings.

Table 11. Summary of NIPSCO's Achievement of Indiana IRP Rule at 170 IAC 4-7-7

IRP Rule	IRP Rule Description	Finding
4-7-7	To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	**Mostly**

6.1 RESOURCE SCREENING TABLE

The IRP narrative discusses the supply and demand side resources available for selection in Aurora. NIPSCO conducted an all-source RFP to utilize in the modeling for this IRP. NIPSCO's RFP results resulted in wind, solar, battery storage, solar hybrid, thermal, and hydrogen resources that were offered as Power Purchase Agreements ("PPAs") and asset sales. Table 12 and Table 13 show the RFP resource cost summary for PPAs and asset sale resources by technology, respectively. NIPSCO used these results to develop tranches of resources that could be input into Aurora for the capacity expansion plan modeling. In addition to the RFP resources, NIPSCO offered the Sugar Creek uprate project, DER distribution deferral projects, energy efficiency, and demand response resources.

Table 12. RFP Bids[26]

Tranche	ICAP (MW)	Heat Rate (Btu/kWh)	Energy Price ($/MWh)	Capacity Price ($/kW-mo)	First Eligible Start Year**	PPA Term (years)	Escalation Rate
Wind P1	500		$48.37		2025	20	0%
Wind P2 (Non-LRZ 6)	835		$33.28		2024	15	0%
Solar P1	825		$49.73		2024	20	0%
Solar P2	588		$37.50		2024	17	0.9%
Solar + Storage P1	300:150^		$39.00	$7.43	2025	15	0%
Solar + Storage P2	1,135:478^		$44.49	$6.14	2023	20	0%
Storage P1	863			$11.95	2025	19	0.2%
Gas Peaking P1	443	10,244	*	$6.47	2026	20	0%
Gas Peaking P2	193	10,238	*	$8 – $9	2025	20	2.1%
Gas CC P1	1,365	6,627	$0.98*	$8.89	2024	20	0.1%
Other Thermal P1	50	12,500	$2 – $3*	$5 – $6	2024	10	
Other Thermal P2	150			$3 – $4	2026	10	2.0%
Hydrogen P1 – Enabled Peaker	193	10,238	*	$9 – $10	2025	20	
Hydrogen P2 – Electrolyzer Pilot	20			$25 – $30	2026	20	

Notes:
Red-colored price information shown as a range to protect confidentiality when tranches are composed of a limited number of bids.
^Capacity for Solar + Storage tranches is represented in the format of "Solar:Storage."
*Fuel and emission variable costs are additive to the Energy Price and are incorporated in the portfolio modeling for the Gas Peaking P1, Gas Peaking P2, Gas CC P1, Other Thermal P1, and Hydrogen P1 tranches.
**First Eligible Start Year indicates the first year some part of the tranche is expected to be available, although capacity is available to start in subsequent years according to bidder information; this is incorporated in the portfolio modeling.

Table 13. RFP Asset Sale Bids[27]

Tranche	ICAP (MW)	Heat Rate (Btu/kWh)	First Eligible Start Year**	Asset Sale ($/kW)
Solar A1	1,250		2025	$1,282
Solar A2	1,150		2025	$1,603
Solar + Storage A1	901:305^		2024	$1,346
Solar + Storage A2	549:275^		2025	$1,167
Storage A1	406		2025	$984
Gas Peaking A1	369	11,471	2024	$575
Gas CC A1	650	6,540	2026	$1,100 - $1,300

Notes:
Red-colored price information shown as a range to protect confidentiality when tranches are composed of a limited number of bids.

[26] NIPSCO 2021 IRP, Figure 4-9, page 90.
[27] NIPSCO 2021 IRP, Figure 4-10, page 90.

7 Resource Portfolios

Section 7 describes our assessment of NIPSCO's performance in meeting the requirements of 170 IAC 4-7-8 of the Indiana IRP Rule. Please see Table 14 below for our findings.

Table 14. Summary of NIPSCO's Achievement of Indiana IRP Rule at 170 IAC 4-7-8

IRP Rule	IRP Rule Description	Finding
4-7-8 (a)	The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	**Met**
4-7-8 (b)	With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential future scenarios, including the alternative scenarios required under subsection 4(25) of this rule.	**Met**
4-7-8 (b)	(2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	**Mostly**
4-7-8 (b)	(3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	**Partial**
4-7-8 (c)	Considering the analyses of its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	**Met**
4-7-8 (c)	(2) Identification of the standards of reliability.	**Mostly**
4-7-8 (c)	(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	**Met**
4-7-8 (c)	(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	**Met**
4-7-8 (c)	(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	**Met**
4-7-8 (c)	(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	**Not Met**
4-7-8 (c)	(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio; (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule; (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio; and (D) The utility's ability to finance the preferred resource portfolio.	**Mostly**
4-7-8 (c)	(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties and (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	**Mostly**
4-7-8 (c)	(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	**Partial**

4-7-8 (c)	(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including to the changes in the following: (A) Demand for electric service; (B) Cost of a new supply-side resources or demand-side resources; (C) Regulatory compliance requirements and costs; (D) Wholesale market conditions; (E) Changes in Fuel costs; (F) Changes in Environmental compliance costs; (G) Technology and associated costs and penetration; (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	**Met**

7.1 PORTFOLIO DEVELOPMENT

NIPSCO used a two-step modeling process to determine retirement dates for Michigan City Unit 12, Schahfer gas-fired Units 16AB, and the Sugar Creek units, as well as the replacement resources for those retired units. In the first step, which NIPSCO refers to as the existing fleet analysis, NIPSCO modeled different retirement dates for Michigan City Unit 12, Schahfer Units 16AB, and Sugar Creek. NIPSCO evaluated 8 different portfolios that looked at retirement dates of 2024, 2026, 2028, and 2032 for Michigan City Unit 12; retirement dates of 2025 and 2028 for the Schahfer 16AB units; and retirement of Sugar Creek in 2032, conversion of Sugar Creek to hydrogen in 2032, or continuing to operate Sugar Creek through the planning period. This existing fleet analysis was evaluated through portfolio optimization within Aurora. As NIPSCO said in the IRP, "The portfolio optimization modeling was performed for both the winter and summer peak seasons and was designed to minimize the net present value of revenue requirements, with certain constraints for reserve margins, maximum off-system energy sales, and resource eligibility." [28]

Once NIPSCO identified a preferred portfolio from the existing fleet analysis, the second step was to model replacement portfolios to determine the replacement capacity. NIPSCO described the process by saying:

> *Based on the nine replacement concepts, NIPSCO then developed specific portfolios to fit each theme. This was done through a combination of the Aurora model's portfolio optimization capability and expert judgment to adjust portfolio concepts based on optimization analysis and available RFP bids.*[29]

NIPSCO developed replacement resource concepts based on the idea of "dispatchability" of resources and the CO_2 emission intensity of each portfolio.[30] On the emissions concept, NIPSCO evaluated portfolios designed to fall into the categories of either high, mid, or low carbon emissions. NIPSCO categorized dispatchability by the different considerations of the reserve margin requirement. Under the current construct, portfolios are required to meet a capacity obligation based on the utility's coincident MISO peak (which occurs in the summer). For the

[28] NIPSCO 2021 IRP, page 210.
[29] NIPSCO 2021 IRP, page 223.
[30] NIPSCO 2021 IRP, page 222.

assumed two-season requirement, portfolios must meet the modeled summer and winter peak. NIPSCO said that the Enhanced Reserve Margin portfolios:

> *[m]ore fully rely on local resources with longer energy duration capabilities, especially thermal resources. Such a portfolio category recognizes the need for local resources during emergency conditions and anticipates future MISO market policy developments that may reduce the capacity credit for resources with limited energy durations, such as four-hour batteries.*[31]

Figure 4 below shows the nine replacement portfolios that NIPSCO modeled across the dispatchability and emissions concepts.

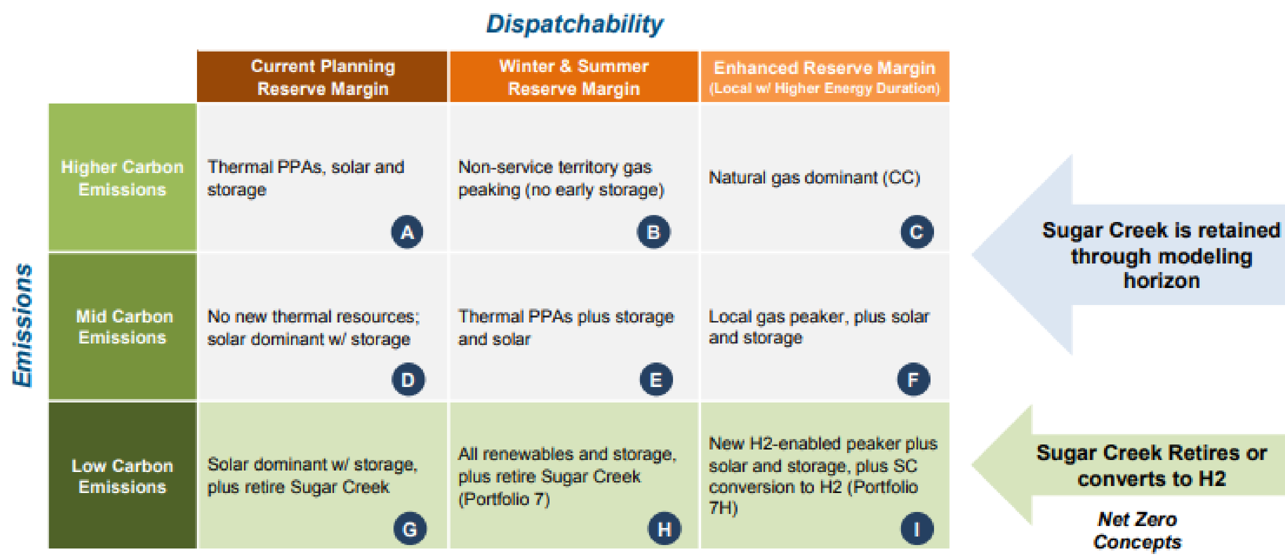

Figure 4. NIPSCO Replacement Portfolios[32]

7.1.1 Existing Fleet Analysis

The Existing Fleet Analysis focused on evaluating possible retirement date combinations for Michigan City Unit 12 and Schahfer 16AB gas-fired units, in addition to operational considerations for the Sugar Creek gas plant units. Table 15 below highlights the retirement dates and resulting NPVRR for the 8 portfolios that NIPSCO modeled.

[31] NIPSCO 2021 IRP, page 222.
[32] NIPSCO 2021 IRP, Figure 9-11, page 223.

Table 15. NPVRR Comparison for Existing Fleet Portfolios[33]

	Retirement Dates			
Portfolio	**Michigan City 12**	**Schahfer 16AB**	**Sugar Creek**	**NPVRR**
3	2026	2028	Retain	$10,114
4	2024*	2028	Retain	$10,125
2	2028	2028	Retain	$10,130
6	2026	2025	Retain	$10,138
1	2032	2028	Retain	$10,149
5	2028	2025	Retain	$10,161
7H	2028	2025	Convert to H2	$10,471
7	2028	2025	Retire 2032	$10,531

**NIPSCO reports this retirement date is not a viable pathway due to implementation timing*

As Table 15 indicates, the NPVRR results for Portfolios 1 – 6 are within 0.50% of each other. The top four least expensive portfolios included a 2024, 2026, or 2028 retirement date for Michigan City Unit 12.

In the IRP, it states that:

> *NIPSCO's preferred existing fleet portfolio strategy is to retire Michigan City 12 between 2026 and 2028, to optimize the retirement timing of Schahfer 16A/B between 2025 and 2028, and to keep open the option of retiring or retrofitting the Sugar Creek plant in the 2030s based on environmental policy evolution and technology advancement.*[34]

NIPSCO identified Portfolio 3 as the preferred portfolio from the existing fleet analysis that would determine the retirement dates to model for the replacement analysis. Table 16 shows the retirement scorecard comparison for Portfolio 3 and Portfolio 6. Given the close NPVRR and scorecard results between these two portfolios, we believe it will be important for NIPSCO to continue to evaluate the optimal retirement dates for Michigan City Unit 12 and Schahfer Units 16 AB.

Table 16. Retirement Portfolio Scorecard[35]

Metric	**Portfolio 3**	**Portfolio 6**
Cost to Customer	$10,114	$10,138
Cost Certainty	$2,766	$2,487
Cost Risk	$11,947	$11,773
Lower Cost Opportunity	$9,181	$9,287
Carbon Emissions (Million Tons)	28.5	28.5
Employees	-127	-131
Local Economy	-$10	-$10

[33] NIPSO 2021 IRP, Figure 9-5, page 215.
[34] NIPSCO 2021 IRP, page 219.
[35] NIPSCO 2021 IRP, Figure 9-9, page 218.

7.1.2 Replacement Analysis

Portfolio 3 from the existing fleet analysis was then used as the basis for the retirement dates that were modeled for the replacement analysis, which included Michigan City Unit 12 retiring in 2026, Schahfer gas-fired 16AB units retiring in 2028, and Sugar Creek gas units continuing to operate. NIPSCO developed replacement portfolios based on the carbon emissions and dispatchability themes discussed in Section 7.1.

NIPSCO said they have "identified Portfolio F as a preferred near-term replacement portfolio concept, with the potential to pivot towards Portfolio I based on continued RFP bid diligence, technology evolution, and potential federal policy changes."[36] We would recommend that Portfolio E be considered as a preferred replacement portfolio, especially given that it meets the winter and summer reserve margin requirements, and contains additional battery storage resources in place of the natural gas combustion turbine contained in Portfolio F. Table 17 shows the NPVRR comparison for Portfolios A through F in addition to the dispatchability category for each portfolio. Portfolio E is only 0.39% higher on a NPVRR basis when compared to Portfolio F, which is less than the 3.5% NPVRR difference that exists between Portfolio F and Portfolio I.

Table 17. NPVRR Comparison for Replacement Portfolios (Millions of $)[37]

Portfolio	NPVRR ($Millions)	Dispatchability	Carbon Emissions
C	$10,312	Enhanced	Higher
B	$10,332	Winter & Summer	Higher
F*	$10,426	Enhanced	Mid
D	$10,438	Current	Mid
A	$10,461	Current	Higher
E	$10,467	Winter & Summer	Mid
I	$10,792	Enhanced	Low
G	$11,042	Current	Low
H	$11,090	Winter & Summer	Low

Figure 5 shows the different components of the replacement analysis scorecard that NIPSCO utilized to evaluate the replacement portfolios. We appreciate that this scorecard has become more sophisticated and quantitative over time. That helps sharpen the IRP analysis and allow for equitable treatment of portfolios. Our main point of feedback is one we gave following the first stakeholder meeting, which is that the positive social and economic impacts should not discriminate between new and existing resources and should extend to the impacts on low-income communities and communities of color. That information is not captured in this scorecard.

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[36] NIPSCO 2021 IRP, page 257.
[37] NIPSCO 2021 IRP, Figure 9-17, page 229.

Objective	Indicator	Description and Metrics
Affordability	Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	Cost Certainty	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR and 75th % range vs. median
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR and 95th % conditional value at risk (average of all outcomes above 95th % vs. median)
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR and 5th % range vs. median
Environmental Sustainability	Carbon Emissions	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions (2024-40 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	Reliability	• The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules • Metric: Sub-hourly A/S value impact and Reliability Assessment scoring
	Resource Optionality	• The ability of the portfolio to flexibly respond to changes in NIPSCO load, technology, or market rules over time • Metric: MW weighted duration of generation commitments (UCAP – 2027)
Positive Social & Economic Impacts	Employees	• *Addressed in Existing Fleet Analysis for existing generation assets; employee numbers will be dependent on specific asset replacements*
	Local Economy	• Effect on the local economy from new projects and ongoing property taxes • Metric: NPV of property taxes from the entire portfolio

Figure 5. Replacement Analysis Scorecard[38]

Table 18, below, shows the comparison of Portfolios E and F across the different replacement analysis scorecard metrics. In summary:

- On the cost to customer metric, the difference in NPVRR between the two portfolios is in the noise at 0.39%.
- Portfolio E has more cost certainty and less cost risk for the highest scenario NPVRR when compared to Portfolio F.
- Portfolios E and F are comparable on the cost risk metric for stochastic 95% conditional value at risk ("CVAR").
- Portfolio F scores slightly better on the lower cost opportunity metric.
- Portfolio E has slightly lower carbon emissions, but Portfolio F has a higher composite reliability and resource optionality scores.
- Portfolios E and F are extremely close on the local economy metric representing the NPV of property taxes.

One of the additional analyses that NIPSCO completed for the 2021 IRP was determined added value in sub-hourly energy and ancillary services markets through the utilization of CRA's ESOP model. The main finding from this analysis was that "the most significant upside is for

[38] NIPSCO 2021 IRP, Figure 9-16, page 228.

battery technology, particularly in the regulation market."[39] In contrast, the analysis found that for CTs, "regulation opportunities are only available when the unit is already operating for energy, limiting the upside when compared to the battery storage projections."[40] As discussed in Section 3.3, CRA's analysis found that battery storage resources had the highest value stream for ancillary services. Portfolio E has a larger reduction in cost due to this value compared to Portfolio F.

Table 18. Scorecard Comparison between Portfolio F and Portfolio E[41]

Scorecard Metric	Measurement	Portfolio F	Portfolio E
Cost to Customer	30-Year NPVRR	$10,426	$10,467
Cost Certainty	Scenario Range NPVRR	$2,748	$2,538
Cost Risk: High Scenario NPVRR	Highest Scenario NPVRR	$12,243	$12,126
Cost Risk: Stochastic 95% CVAR	Average Above 95th Percentile	$97	$98
Lower Cost Opportunity	Lowest Scenario NPVRR	$9,495	$9,588
Carbon Emissions	Cumulative 2024-2040 Emissions	28.5	27.3
Reliability	Composite Reliability Score	7.38	6.08
Reliability	Reduction to 30-Year NPVRR	-$173	-$332
Resource Optionality	MW-Weighted Duration of 2027 Generation	22.12	21.15
Local Economy	NPV of Property Taxes	$416	$413

In the IRP narrative, NIPSCO identified Portfolio F as the preferred replacement capacity plan, but discusses the potential to pivot to Portfolio I, which includes the "H2 Enabled Peaker" instead of the gas turbine peaker in Portfolio F:

> *NIPSCO has identified Portfolio F as a preferred near term replacement portfolio concept, with the potential to pivot towards Portfolio I based on continued RFP bid diligence, technology evolution, and potential federal policy changes*."[42]

Portfolio I is 3.10% more expensive on a PVRR basis when compared to Portfolio E, which relies on battery storage in place of a thermal or hydrogen enabled peaker plant. In addition to the increased cost from Portfolio I, there are also risks around the difficulties of commercializing hydrogen technology at this level and a question of whether or not the peaker will be able to

[39] NIPSCO 2021 IRP, page 243.
[40] NIPSCO 2021 IRP, page 243.
[41] NIPSCO 2021 IRP, Figure 9-42, page 257.
[42] NIPSCO 2021 IRP, page 257.

operate predominately with hydrogen as the fuel source for the plant. Within the IRP, NIPSCO identified uncertainties with hydrogen, which include: technology advancement with electrolyzer capital and operating costs; creation of federal incentives; developments in hydrogen transmission, distribution, and storage infrastructure; MISO market dynamics; broader carbon emission reduction policies; and the price of natural gas.[43]

Given the cost declines that have been observed for storage technologies, and the potential for long duration storage, Portfolio E is a better candidate for preferred portfolio than Portfolio F. At a minimum, Portfolio E should be the portfolio that NIPSCO could pivot to from Portfolio F over Portfolio I, given the cost gap between Portfolios E and I and the many uncertainties surrounding hydrogen viability.

7.1.3 Risk Analysis

Indiana utilities often evaluate risk of portfolios through the utilization of stochastic modeling. We have routinely expressed concern about how stochastics have been applied in several of the Indiana utility IRPs. We continue to have reservations on the use of stochastic modeling, especially when there is no analytical information, e.g., no historical data upon which to base probabilities, no testing for convergence, and stochastics are inappropriately applied to variables that are uncertain rather than volatile like capital costs.

For this IRP, NIPSCO evaluated risk through the combination of developing scenarios and performing some stochastic modeling runs. The IRP narrative said:

> *NIPSCO has structured its risk and uncertainty analysis to analyze portfolio decisions across both scenario risk and stochastic risk, since the two complementary approaches can be used to answer different questions and quantify risks in different fashions*.[44]

NIPSCO identified the following key uncertainties to be evaluated in the IRP:

- Commodity prices
- Environmental policy[45]
- NIPSCO load growth
- Future value of intermittent resources[46]

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[43] NIPSCO 2021 IRP, pages 106 – 107.
[44] NIPSCO 2021 IRP, page 176.
[45] Carbon pricing, federal subsidies, and federal tax credits.
[46] Capacity credit and hourly generation output.

Table 19 shows whether NIPSCO performed a scenario or stochastic analysis for the uncertainty drivers that were identified. For the stochastic analysis, NIPSCO utilized historical data to develop the distributions used to create the price paths. NIPSCO reports that 500 iterations or draws were used for natural gas and power prices. While it does not appear that NIPSCO explicitly measured convergence, we do think 500 iterations is much more likely to achieve convergence than 100 or 200 iterations. We also commend NIPSCO for appropriately applying the stochastic analysis to variables like natural gas and power prices and not to variables such as capital costs or carbon prices.

Table 19. NIPSCO Evaluation of Uncertainty Variables[47]

Driver	Scenario Analysis	Stochastic Analysis
Natural Gas Price (Monthly and Annual)	X	
Carbon Policy	X	
Federal Incentives	X	
Hourly MISO Power Prices	X	
NIPSCO and MISO Load Growth	X	
Capacity Credit for Solar Resources	X	
Daily Natural Gas Prices		X
Hourly MISO Power Prices		X
Hourly Renewable Generation Output		X

NIPSCO developed four scenario themes to evaluate in the IRP, which included the Reference Case, Status Quo Extended, Aggressive Environmental Regulation, and Economy-Wide Decarbonization. Figure 6 below shows the parameters for each scenario.

[47] NIPSCO 2021 IRP, page 177.

Scenario Name	Gas Price	CO_2 Price	Federal Tech. Incentives	Load Growth	Solar Capacity (ELCC) Credit (Current → 2040)
Reference Case	Base	Base	2-year ITC extension (solar); 1-year PTC extension (60%)	Base	50% → 25%
Status Quo Extended	Low	None	No change to current policy	Lower	50% → 30%
Aggressive Environmental Regulation	High	High	5-year ITC extension (solar) plus expansion to storage; 3-year PTC extension (60%)	Close to Base	50% → 15%
Economy-Wide Decarbonization	Base	None	10-year ITC extension (solar) plus expansion to storage; 10-year PTC extension (60%); tracking further potential federal support for advanced tech including hydrogen and NG CCS	Higher	50% → 15%

Figure 6. NIPSCO's Scenario Parameters[48]

7.2 RELIABILITY ANALYSIS

We reiterate and emphasize our October 20, 2021 comments to NIPSCO on its reliability analysis, particularly as it relates to the blackstart metrics. While NIPSCO heavily relies on this in the selection of its 2021 IRP preferred plan, we appreciate that NIPSCO leaves open the door for further discussions and analysis before investing in a large CT facility.

This is especially important given that this type of reliability analysis is new ground for the industry with much of it not firmly established art. There is plenty of room for judgment and, frankly, disagreements between reasonable people. There is no one right answer to most of the questions addressed. To that end, these comments on the reliability analysis are primarily aimed at identifying positive refinements to what is NIPSCO's forward looking analysis.

Furthermore, as noted by NIPSCO in its IRP, there is a lot of uncertainty in the near term future of policy and technology, particularly as it relates to storage which could provide the same blackstart capability that NIPSCO is seeking. Given that investment in a large CT facility is a long-term commitment for ratepayers with no viable off-ramps if NIPSCO is wrong in this resource selection, it is important for NIPSCO to continue to study this issue and go through another IRP cycle before making any final decisions. We appreciate NIPSCO's acknowledgement of this in its Response to our October 20 comments which states: "NIPSCO will continue to monitor MISO market developments and welcomes continued conversation regarding analytical frameworks and reliability assessments that we might consider for future IRPs."

[48] NIPSCO 2021 IRP, Figure 8-26, page 179.

7.2.1 Regulation

NIPSCO's analysis here looks at incremental value from ancillary services (particularly Figures 9-31, 9-33, and 9-34 in NIPSCO's IRP) which includes a substantial focus on MISO's symmetric, single regulation market (i.e. one product for both up and down). While it is good that NIPSCO did its analysis on that basis, it is worth noting that the majority of independent system operators ("ISO") have moved to asymmetric markets as wind and solar resources have increased.

Having separate markets helps to release constraints on modern resources, providing benefits in several forms. When MISO eventually adopts this practice, the value of the renewable heavy portfolios, as shown for example in the center graph of IRP Figure 9-31 and the opportunity bars of Figure 9-34, will increase. Both wind and solar provide an extremely high quality regulation service. Field demonstrations, for example, in California ISO with both wind and solar PV plants[49] showed that the quality of the regulation response from wind and solar PV was measurably superior to thermal generation. Operating expectation (and FERC's expectation) is that superior regulation performance should result in reduced amounts of regulation being procured, resulting in operating cost savings for all stakeholders. FERC requires that superior performance be rewarded with accompanying market signals.

Further ERCOT experience with wind plants *always* providing down primary frequency response is partly responsible for a *reduction* in the amount of regulation procured by ERCOT as the amount of wind and solar generation has steadily increased. Statistical work in several systems has predicted an increase in the amount of regulation needed with higher variable energy resource levels, but in practice this is usually not observed. Such behavior will likely impact the analysis here, boosting scores of the renewable heavy portfolios.

NIPSCO stated in its November 11th Response that it "agrees that market design changes will impact ancillary services opportunities and that the implementation of an asymmetric regulation market could serve to benefit renewable resources (at least from the perspective of allowing them to monetize ancillary services revenue)" and "would be worth evaluating in the future". However, "NIPSCO's sub-hourly ancillary services analysis was primarily targeted towards the relative value of storage versus gas peaker portfolio additions" noting the challenges of "a fuller portfolio analysis with co-optimized energy and ancillary services dispatch" "across time and against multiple scenarios and portfolios".

While we understand the difficulty of complex modeling exercises, this further underscores the need to wait and perform further analyses. We greatly appreciate NIPSCO's commitment to "continue to monitor [MISO] market developments and [] continued suggestions regarding analytical frameworks that might be useful in future IRPs."

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[49] CAISO/NREL/FirstSolar, "Using Renewables to Operate a Low-Carbon Grid: demonstration of Advanced Reliability Services from a Utility-scale Solar PV Plant".

7.2.2 Blackstart

NIPSCO's blackstart analysis was innovative and most welcome. NIPSCO's slide 40 of its October 12 presentation includes a few up-to-date references for inverter-based resources providing blackstart. The analysis correctly credits energy storage (assumed to be battery energy storage system or "BESS") equipped with grid-forming inverters ("GFM") as a credible resource for providing blackstart. But, there appears to be an assumption that the storage (i.e. the battery energy storage portion) of the solar+storage resources would not have GFM inverters, and therefore could not be used for blackstart.

This appears to result in no credit and correspondingly so for the energy storage portion of those scenarios with solar+storage. The genesis of this assumption is not clear, but it seems to be at odds with state-of-the-art practice. For example, all of the present tranche of solar+storage projects that have been awarded and are under design now in Hawai'i include *as a contractual requirement of the project* that they have grid-forming inverters on the battery portion.[50] It is Hawai'i Electric Light Company's operational expectation to rely on the grid-forming functionality of the BESS to deliver a wide range of operational benefits. This capability will affect the scoring of these solar+storage projects not only for blackstart, but for short circuit strength, inertial response, and possibly fast regulation. Should NIPSCO go forward with scenarios that include solar+storage, they should expect to demand a high level of functionality from these plants, including state-of-the-art GFM capability. The score of scenarios in the IRP evaluation should reflect that, with the expectation that they will probably improve. NIPSCO responded on November 12th:

> The reliability analysis and portfolio scoring assumed that stand-alone storage systems will be fitted with grid-forming inverters, while the storage part of solar plus storage resources will be fitted with grid-following inverters. The solar plus storage resources are configured with the storage system operating behind the solar inverter; therefore, it is unlikely for the combined inverter to be grid forming. The CAC's comment is correct that the scoring will be impacted if a decision is made to require grid-forming inverters also for the storage component of solar plus storage resources. However, this will only impact Portfolios A, D, and G that include 150MW of storage within the 450MW of solar plus storage capacity block.

We appreciate this acknowledgement, but encourage NIPSCO to address this issue, even if it only impacts a few of the portfolios, particularly since these portfolios, Portfolios A, D, and G, received the lowest cumulative scores from the Portfolio Reliability Ranking at 52%, 47%, and 45%, respectively.[51] It is critical to correct any errors to ensure transparency and sound decision-making.

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[50] For example: Docket 2017-0352, Order # 36604, 10-9-2019. 'Application to HELCO for PPA for Renewable Dispatchable Generation with ENGIE 2020 Project CoHI1' before the Hawai'i PUC.
[51] NIPSCO 2021 IRP, page 255.

7.2.3 VAR Support

NIPSCO correctly points out that inverter-based resources ("IBRs"), including solar PV and wind, have the capability to provide reactive power and to perform voltage regulation *regardless* of whether they are generating. BESS can provide voltage regulation regardless of whether it is charging, discharging, or idle. Thus, IBR resources *that are specified accordingly* can provide this essential reliability service all the time. In comparison, thermal resources must be committed and running. For fossil generation that is expected to have a relatively low capacity factor, this means that the voltage support will be relatively rare. That benefit is only realized when the generator is running and producing MW, at least at the unit minimum. The exception is for small simple cycle combustion turbines, some types of which can be equipped with a clutch that allows operation of the generator as a synchronous condenser. This feature adds to the capital cost, but can be a significant benefit to systems where the CT is expected to run rarely. Los Angeles Department of Water and Power has relatively new units with this feature that are reputed to be run in condenser mode most of the time. Commercial arrangements for this function are non-standard, and the losses associated with this function are non-trivial. The capability is not commercially available on large gas generation, including combined cycle plants. It must be specified at the time of initial design (i.e., no retrofits). NIPSCO noted in its November 12 response comments that it agrees with CAC's "comments regarding the relative availability of dynamic VARs from inverter-based resources and thermal resources."

With regard to the reliability metrics on Figures 9-39, 9-40, and 9-41 (line 5 of the tables) in NIPSCO's IRP, it seems at odds that all the options result in the same score with the arguably better features of the IBR options. When we raised this in our October comments, NIPSCO responded, "Given the local nature of reactive power, the 'VAR Support' reliability metric is designed to quantify the ability of each portfolio to deliver its dynamic VARs to load centers. The availability of dynamic VARs, however, was not considered in the evaluation due to its dependence on commitment decisions that are beyond the scope of this investigation." We look forward to further discussion on this topic before the next IRP submission and before any decisions are made regarding the construction of new powerplants.

7.2.4 Ramping

The aggregate dispatchability, and particularly the 1-minute and 10-minute ramping results seem unnecessarily constrained by traditional views of thermal generation as the primary resource for net load following. For example, the scenarios with energy storage but no thermal generation received quite poor scoring. This seems at odds with the reality that, properly managed, the energy storage elements alone, or the combined resources of solar plus energy storage, can be available for ramping duty every hour of every day. It is a fact that the combined constraints of sunlight and state of charge can constrain capability.

Further, ITC constraints that penalize charging the batteries from the grid present an economic (though not physical) constraint that must be respected. But the resources are synchronized and ready *instantly* to provide a very high quality, fast, and finely controllable ramping response all the time. All resources that provide ramping must respect a variety of limits. Surely the fact that, under some conditions, the energy storage resource cannot draw ramping power from the grid is less constraining than the reality that a fossil plant can *never* draw power from the grid.

The very high scores for the fossil resources would appear to disregard the reality that these resources must be committed and dispatched to provide ramping services in these time frames. It is the economic expectation that these plants will have relatively low capacity factors, so they will tend to not be running. The plants, and particularly the combined cycle option, are subject to minimum dispatch limitations, minimum start times, minimum run times, and minimum down times, all of which have the potential to negatively impact their ability to provide ramping when needed. This is especially the case for unexpected ramps.

We appreciate that NIPSCO said in its Response that it "will continue to study this topic and take into account CAC's other comments regarding analytical approaches around reliability risk. For example, sub-hourly stochastic analyses of load, renewable output, day ahead forecast error, and other factors might be useful frameworks for assessing ramping needs at various intervals." NIPSCO's Response seems to acknowledge that they did not consider whether the resources would be committed and running, and this should be corrected and reanalyzed before any decisions to procure fuel-dependent, long-term gas generation.

7.2.5 Short Circuit Strength

The technical issues surrounding dropping short circuit strength are a legitimate concern. It is worth noting that every scenario includes synchronous condensers, which help mitigate the concern. The combined issues of sensitivity of IBRs to low short circuit levels and the potentially adverse impact of low short circuit current *from the IBRs* on protection are real.

However, both issues are receiving a great deal of attention from the industry on several fronts. As with the ramping observation, the fossil resources only provide short circuit strength when they are committed. In comparison, grid forming inverters from the new energy storage (either stand-alone or in the solar+storage facilities) can expect to be synchronized all the time. Again, as an example, it is the current reality in Kaua'i and the near future reality on Hawai'i that the system can run and be protected successfully with a single synchronous condenser (Kaua'i today) or an extremely limited number of synchronous machines, relying on their solar+energy storage projects to provide the needed system support. That NIPSCO's end short circuit scoring resulted in such extreme (zeros, half points, and ones only) seems at odds with a more nuanced reality.

NIPSCO said in Response to CAC's Comments that:

> All inverters on the market, including grid forming ones, have limited short circuit current capability, and thus are not expected to appreciably increase the short circuit strength of the grid. Compounding this limitation is the uncertain phase angle of the short circuit current (reactive or active) which appears to depend on the inverter control system and thus manufacturer specifics. Given these limitations and uncertainty, a prudent assumption was made in this study that grid forming inverters can operate successfully at low short circuit ratios and thus assumed to cause no harm. However, they were not assumed to enhance the grid short circuit strength.

NIPSCO is correct that grid forming inverters ("GFM") deliver some short circuit current, but not as much as a similarly sized synchronous machines. However, GFM inverters don't <u>need</u> short circuit current <u>from</u> the grid to operate properly, so they can tolerate a weak grid and therefore no condensers are needed. NIPSCO is improperly treating short circuit strength concerns as if they apply evenly across all portfolios.

8 Short Term Action Plan

Section 8 describes our assessment of NIPSCO's performance in meeting the requirements of 170 IAC 4-7-9 of the Indiana IRP Rule. Please see Table 20 below for our findings.

Table 20. Summary of NIPSCO's Achievement of Indiana IRP Rule at 170 IAC 4-7-9

IRP Rule	IRP Rule Description	Finding
4-7-9 (a)	A utility shall prepare a short term action plan as part of its IRP, and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	**Met**
4-7-9 (b)	The short term action plan is a summary of the utility's preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9) of this rule	**Partial**
4-7-9 (c)	The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio and (B) The criteria for measuring progress toward the objective.	**Met**
4-7-9 (c)	(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives.	**Partial**
4-7-9 (c)	(3) The implementation schedule for the preferred resource portfolio.	**Met**
4-7-9 (c)	(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	**Not Met**
4-7-9 (c)	(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	**Not Met**

NIPSCO's Short-Term Action Plan provides a helpful summary of the actions they are likely to take over the Short-Term Action period. NIPSCO reports that it will start the process to plan for the retirement of Michigan City Unit 12 and the Schahfer 16AB units, while "leaving flexibility in ultimate timing."[52] NIPSCO also says that the Company "will perform due diligence on the short-list of gas peaker and storage bids and will conduct additional targeted RFP solicitations and associated portfolio analysis if current projects do not meet all reliability and other considerations inherent in the preferred portfolio."[53] We would advise NIPSCO to take this charge broadly because prudence requires re-evaluation of decisions that are not sunk. NIPSCO ought to follow the path that allows optionality and flexibility and continue to consider the feasibility of Portfolio E in place of its preferred portfolio, consider whether new technologies such as long duration storage can better and more cost-effectively meet NIPSCO's need, and consider how changing volatility, inflation, and other pricing concerns would influence its decision making. We look forward to participating in NIPSCO's next IRP process and continuing dialogue in the interim.

[52] NIPSCO 2021 IRP, page 265.
[53] NIPSCO 2021 IRP, page 265.

REFERENCED DISCOVERY RESPONSES

Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Informal Request 1
2021 Integrated Resource Plan

<u>CAC Informal Request 1-009:</u>
Please refer to Confidential Appendix D, tab named "Generic Replacement Costs". a. Please provide the source of the capital costs for the generic resources provided in this worksheet.
<u>Objections:</u>
<u>Response:</u>
a. The capital cost projections for solar and storage resources were based on information received via the RFP, Charles River Associates, Inc.'s ("CRA's") recent project experience, and the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("NREL ATB") 2020 mid decline curves. For example, for solar resources, the average cost from RFP projects was approximately $1,450/kW, and CRA has witnessed recent inflationary pressures driving costs for mid-decade projects even higher. Thus, generic resources were priced at this level in 2030, following the NREL ATB trajectory thereafter. For storage resources, the average cost from RFP projects was just under $1,000/kW, establishing an anchor point for future NREL ATB decline projections to be applied. Note that a range of net costs was developed based on potential extension and expansion of investment tax credits for solar and storage projects, as outlined in Section 8.4 of NIPSCO's 2021 IRP report. The capital costs for the Sugar Creek uprate were sourced from the turbine manufacturer's (General Electric) estimates for the uprate. Capital costs for the H2-enablement retrofit were based on 30% of the capital cost of a new combined cycle unit, as per indicative pricing estimates sourced from public research and turbine manufacturer quotes. The capital costs for the distributed energy resources were based on utility-scale solar and storage resources with a 20% distribution capital cost premium, less an offset for deferred distribution system investment, as further described in NIPSCO's response to CAC Informal Request 1-017.

Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Informal Request 1
2021 Integrated Resource Plan

CAC Informal Request 1-011:
Please refer to Confidential Appendix D, tab named "Generic Replacement Costs" and "RFP Resource Tranches". a. Please confirm if new solar and storage generic replacement resources were only allowed to be selected between 2030 and 2040. b. Please confirm if the RFP tranche resources modeled in Aurora were only allowed to be selected between 2024 and the end of 2026. c. If the answer to subpart (b) is "yes," what resources, if any, could be selected between 2027 and 2030? d. Please confirm if Aurora was allowed to select any new resources between 2027 and 2029 aside from the Sugar Creek Uprate and the DER resources.
Objections:
Response:
a. Confirmed. b. From a modeling perspective, RFP tranches Storage P2 and Storage A2 were available for selection in 2027, reflecting the fact that the online dates offered for RFP resources in these tranches implied that the 2027/28 MISO planning year would be the first year capacity would be accredited. The Solar + Storage P2 tranche was available for selection in 2023, given the online dates offered for RFP resources in that tranche. All other RFP resources were allowed to be selected between 2024 and 2026. c. In addition to the tranches noted in NIPSCO's response to subpart b. of this request, the Sugar Creek Uprate and distributed energy resources were also available during this time period, as discussed subpart d. d. Aurora was not allowed to select any new resources between 2027 and 2029 aside from those referenced in NIPSCO's response to sub-part c. The modeling framework was set up this way to evaluate actual RFP projects that could be used to meet capacity needs that may arise through 2026 with the potential retirement of Michigan City Unit 12 and Schahfer Units 16AB, rather than

allow for more speculative resource costs in the subsequent years to impact resource selection and revenue requirement accounting.

Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Informal Request 1
2021 Integrated Resource Plan

CAC Informal Request 1-021:
Please refer to Figure 9-42 on page 257 of the 2021 IRP. Please explain how the reliability metric "Reduction to 30-Year NPVV (Ref Case) $M" is calculated for each replacement portfolio and provide the workbooks with all formulas and links intact used to make that calculation.
Objections:
Response:
The "Reduction to 30-Year NPVRR (Ref Case) $M" metric was based on the results from the sub-hourly modeling performed in the ESOP model, as described in Section 9.2.6 of the IRP. Please refer to Section 9.2.6.6 of the 2021 IRP for the explanation of how the metric was calculated. As noted, the annual $/kW-yr incremental value from the ESOP analysis was attributed to each MW of storage, solar plus storage, or gas peaker capacity in all portfolios to arrive at an aggregate total net present value impact. This metric is intended to present the potential value that could be realized by flexible resources in the portfolios in the sub-hourly energy and ancillary services markets on an NPVRR basis. Please refer to the spreadsheet entitled "CAC Informal Request 1-021 Attachment A" for a documentation of the calculations performed to develop the scorecard metric. The "AS Value" tab contains the incremental $/kW-yr resource-specific values that were calculated from the ESOP model analysis in nominal $ across all four market scenarios. Note that these are the same values NIPSCO presented in Figure 9-33 of the IRP report, although the report figure is in real 2020$. These values are then applied to each new resource in the nine portfolios in the "AS Value owned resources Calcs" and "AS Value for PPAs Calcs" tabs. The "Summary" tab calculates the aggregate portfolio impact and summarizes the net present value of results. The summary across all scenarios matches Figure 9-34 from the 2021 IRP, with the Reference Case results (shown in Cells B3:B11) used for the scorecard metric.

See Excel Sheet for CAC Informal Request 1-021 Attachment A

CAC WRITTEN COMMENTS PROVIDED IN STAKEHOLDER PROCESS

Comments of CAC on
NIPSCO's First 2021 IRP Stakeholder Workshop

Submitted to NIPSCO on April 9, 2021

Citizens Action Coalition of Indiana ("CAC") submits these comments on the materials presented during NIPSCO's March 19th Integrated Resource Plan ("IRP") stakeholder workshop.

1 Metrics

The purpose of metrics is to allow for consideration of a range of factors in selecting a preferred plan. We concur with that purpose. However, we believe the currently proposed metrics overemphasize certain data coming out of the IRP, do not equitably capture the benefits of different resource choices, and do not always capture the very objective they were intended to define. We would also propose an additional metric to address an area of concern currently not captured by NIPSCO – that is equity.

The metrics overemphasize the data coming out of the IRP, because the three rate stability metrics appear to all be premised on the stochastic analysis that NIPSCO will perform. We understand NIPSCO's stochastic analysis to be testing daily natural gas price volatility, hourly power price volatility, and hourly wind and solar renewable output volatility. Conceptually, these seem like appropriate areas to evaluate probabilistically though it is not clear how NIPSCO would correlate them, because, for example, wind and solar output is connected to power price indirectly through weather. We would not expect renewable output to correlate to a single power price, so it is not clear how these variables would be sampled so that they all appropriately relate and capture the range of possible outcomes. Stochastic analysis can be useful, but it is also very easy to unintentionally do it poorly. Even if there were no concern about NIPSCO's stochastic methodology, we are concerned that "rate stability" would be premised exclusively on the stochastic analysis, because it does not capture the range of cost risks, several of which are better evaluated in scenarios/sensitivities. This would include lower capital costs, regulatory risk, and others. Furthermore, the proposed rate stability metrics blend cost impacts throughout the planning period when arguably we should be more concerned about near-term impacts given their greater certainty. Finally, we do not think this methodology is actually representing revenue requirements. It is our understanding that Aurora is incapable of calculating revenue requirements, thus all capital costs are represented as a carrying charge (levelized charge) rather than as assets with depreciation schedules, which can have a very different rate impact.

The employee related metrics do not equitably capture the benefits of different resource choices because it counts only NiSource jobs. The economic impact of NIPSCO's portfolios extends not just to its own employees but also contractors who work on NIPSCO driven programs like energy efficiency. We think at least direct contractors working for NiSource should also be counted.

There are several metrics that do not capture the objective intended. First, NIPSCO seems to intend "operational flexibility" to cover several different objectives including black start capability and ramping capability. Ramping is currently an economic product in MISO that is quickly saturated, and we believe it will continue to be for many years to come. We also think it is likely that NIPSCO's modeling will show, as the modeling of other MISO utilities has shown, that large ramps are happening for economic, and not reliability, reasons. Therefore, we do not believe it makes sense to use dispatchable supply-side MW as the indicator of operational flexibility, because the economic impact of ramping will already be captured in the Company's modeling. Indeed, even if ramps became a reliability concern, much further down the line, e.g. when MISO get 75% of its energy from renewables, this metric would not capture the flexibility of load, which would have significant value. If there is a concern for black start capability, we would recommend making the count of black start units, up to the level needed, its own metric.

Because of the change in NIPSCO's firm load obligation following its most recent general rate case, it may be prudent to also include a metric that allows comparison of the volumes of spot purchases and sales.

We would also recommend the addition of a diversity, equity and inclusion ("DE&I") metric. However, because a DE&I metric should be reflective of the preferences of affected communities, it makes the most sense to solicit the feedback of those communities. Since those preferences may vary amongst different service territories, we would propose the following as interim, not final, DE&I metrics for NIPSCO. First, a metric that measures whether emitting units in each portfolio are located in low-income communities and/or communities of color. An example of this as it relates to peaker plants in New Mexico is given below.

As it relates to all these metrics, we would also emphasize that it is more important to present useful information than information that can fit neatly into a table. It is often the case that having a temporal sense of the information that metric is evaluating is quite useful, e.g., how purchases and sales change over time. However, tables/scorecards cannot convey that kind of detail. They sacrifice utility of information for brevity of information.

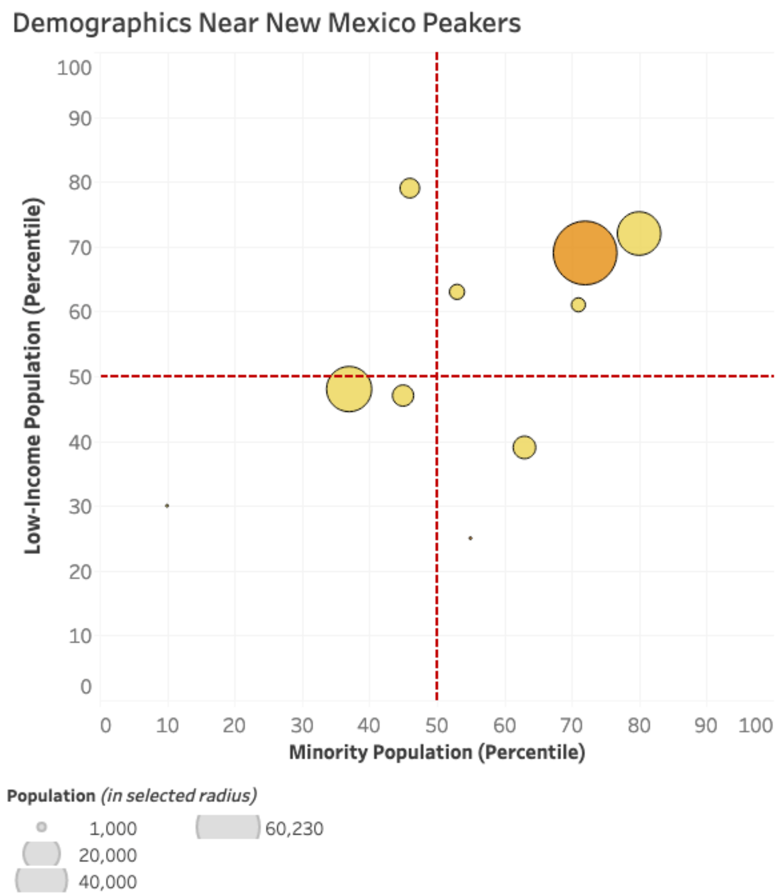

Figure 1. Demographics Near New Mexico Peaker Plants[1]

The circle size indicates the population within a given radius of the plant and the color, in this case, distinguishes between peakers at their own site versus those co-located with a combined cycle plant. We would also note that this is another example of useful information that cannot easily be included in a scorecard. For NIPSCO's purposes, we would recommend keeping the low-income and community of color axes, but changing the color coding to reflect the fuel burned at emitting units. We would note that a similar graph, but for all fuel types, could be used to identify some of the positive and negative impacts as well as the equity of those impacts arising from replacement generation once the locations of replacement resources are identified.

We would also propose a second DE&I metric that attempts to capture the potential for benefits of new resources (both supply and demand-side) to low-income communities and communities of color in NIPSCO's service territory by quantifying the total investment potential for these communities. That investment could include dollars spent on energy efficiency, dollars spent on solar, etc. This is a metric that will need future refinement, but should be

[1] https://www.psehealthyenergy.org/our-work/energy-storage-peaker-plant-replacement-project/new-mexico/

accompanied by consideration of programs that will directly address the objective of the metric. Ideally, NIPSCO would also be evaluating programs that directly impact affected communities as part of its IRP, e.g., low-income community solar, low-income electric vehicle incentives, investment in "green zones" in communities located near NIPSCO's power plants, etc.[2]

Again, we view these as first step DE&I metrics and think it would be very helpful for NIPSCO to more formally and intentionally solicit feedback on DE&I metrics from the very communities that would be influenced by these metrics.

2 Load Forecasts

We recommend that NIPSCO's load forecast methodology be updated to robustly capture the impacts of appliance standards that were recently implemented or will be implemented in the future. Itron's SAE model uses a version of the EIA's Annual Energy Outlook ("AEO") projections for efficiency of certain residential[3] and commercial[4] sector end-uses that accounts for at least the known appliance standards. Those standards are given in the AEO's documentation.[5]`

3 Scenarios

Overall, we thought the proposed scenarios – Reference Case, Status Quo Extended, Aggressive Environmental, and Decarbonization/Electrification – represented a good mix of outcomes and a manageable number of scenarios. Because they were presented mostly conceptually, there were a few details that we cannot speak to yet (for example, what the low/high load forecasts look like). But we would offer our opinion now on the differences in the range of solar Effective Load Carrying Capability ("ELCC") values between scenarios. We presume this is based on MISO's Renewable Integration Impact Assessment ("RIIA") study and would like to flag that the trajectory of utility scale solar ELCCs has changed quite dramatically in MISO's most recent version of the study published on February 10, 2021. It would be important to use that most recent study and to correctly assign utility-scale PV ("UPV") ELCCs separately from distributed PV ("DPV") ELCCs because they do differ.[6]

Similarly, the details of the reserve margin that NIPSCO intends to model are quite important. MISO is still in the process of developing its new resource adequacy construct and a majority of

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[2] Clearly, there is an implementation component to this that is important and complementary. And that is to weigh where to invest those dollars also using these metrics (and other metrics) once NIPSCO moves from the generic resources modeled in the IRP to the specific resources it would seek to implement. At that stage, NIPSCO could also supplement this analysis by considering whether historic investment has gone equitably towards affected communities.

[3] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=30-AEO2021&cases=ref2021&sourcekey=0

[4] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=32-AEO2021&cases=ref2021&sourcekey=0

[5] See here starting at PDF page 14: https://www.eia.gov/outlooks/aeo/assumptions/pdf/summary.pdf

[6] See PDF page 40 of: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

members recently voted to oppose MISO's new thermal accreditation methodology.[7] As a result, there is significant uncertainty about what that new Resource Adequacy ("RA") construct would look like, and we think it is important that NIPSCO capture a range of outcomes. This includes but is not limited to a 3 to 4 season construct with reserve margin requirements and capacity accreditations that vary based on season and on planned outages, and an outcome that keeps the current summer-focused annual construct.

4 Electric Vehicles

During the March 19th workshop, there was some discussion about the possibility of modeling EV load as flexible. We think this is very important for the Deep Carbonization/Electrification scenario in particular. A summary of EV charging load shapes from cities across the country was collected by the U.S. Department of Energy in 2013.[8] The report demonstrates visually how responsive EV charging can be to a time of use ("TOU") tariff (or not). For example, Dallas/Ft. Worth did not have a TOU rate in place at the time the data for the report was collected, and their weekday charging profile appears as follows:

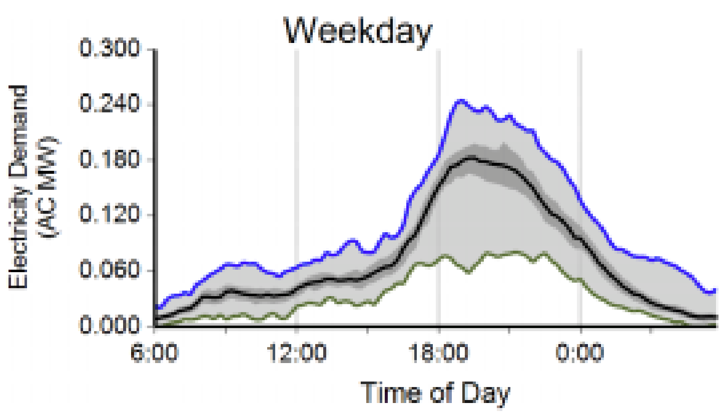

Figure 1. Dallas/Ft. Worth Aggregate Weekday Charging Profile

[7] Durish Cook, Amanda. "MISO, Stakeholders Disagree on Post-storm Accreditation." *RTO Insider*. March 30, 2021. https://rtoinsider.com/rto/miso-post-storm-accreditation-196309/

[8] https://www.energy.gov/sites/prod/files/2014/02/f8/evproj_infrastructure_q22013_0.pdf

San Diego, on the other hand, had a TOU rate, and its charging profile looked substantially different as a result:

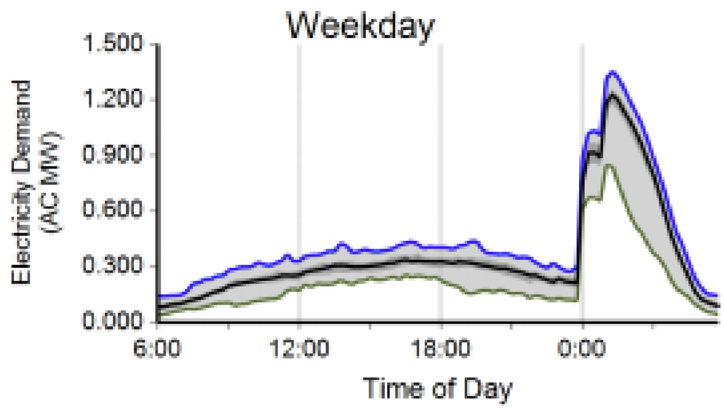

Figure 2. San Diego Aggregate Weekday Charging Profile

Throughout the DOE report, it is possible to tell just by visual inspection which cities had a TOU rate and which did not, demonstrating that EV charging is indeed very responsive to price. We would strongly encourage NIPSCO to investigate the EV TOU tariffs that exist now to determine what pricing results in this level of responsiveness.

5 Modeling DSM

Though it was not discussed in the March 19th IRP workshop, we also wanted to address the modeling of DSM previously raised in NIPSCO's DSM Oversight Board discussions. In NIPSCO's prior MPS (AEG 2016), the Company used a residential line loss factor of 2.41% and a C&I line loss factor of 4.11% to convert DR (and potentially EE) impacts from the meter to the generator. For the current MPS, the Company is proposing to use the "peak" line loss factors shown in the following table:

Sector	Previous MPS[9]	Average Line Losses[10]	"Peak" Line Losses
Residential	2.41%	2.97%	4.11%
Commercial	4.11%	2.65%	3.76%
Industrial		1.65%	2.41%

We would like to understand, first, why the line loss values changed relative to the previous MPS; and, second, why the values are so much lower than is typical for other utilities. The conversion of DSM impacts to generator values can have important implications for the value of these resources. Currently, these conversion factors seem unreasonably low which would lead to an undervaluing of DSM.

[9] 2016 AEG NIPSCO DSM Market Potential Study, page 89.
[10] IURC Cause No. 45456, Company Witness Becker Direct Testimony, Attachment 1-F, page 1.

Comments of CAC on NIPSCO's 2021 IRP October 12th Technical Meeting

Submitted to NIPSCO on October 20, 2021

Overall Thoughts[1]

Citizens Action Coalition of Indiana ("CAC") submits these comments on NIPSCO's October 12, 2021 presentation and review of the CRA/Quanta "draft material" deck. Given the tight timing, these are being provided quickly and at the expense of more careful consideration (and editing). Consequently, these comments should be regarded as advisory, and possibly incomplete.

First of all, this is good practice, and NIPSCO deserves credit for such a forward looking, innovative approach.

It is worth noting that is new ground for the industry. Much of the analysis is not firmly established art. There is plenty of room for judgment and, frankly, disagreements between reasonable people. There's no one right answer to most of the questions addressed.

To that end, these comments are primarily aimed at identifying positive refinements to what is clearly sound, well executed work.

Regulation

The section that looks at incremental value from ancillary services (particularly slides 14, 16, 17) includes a substantial focus on REG. As noted in the webinar and on slide 26, MISO has a single REG product (i.e. up and down are one service). Analysis was done on that basis, which is correct. But it is worth noting that the majority of ISOs have moved to asymmetric markets as wind and solar resources have increased. Having separate markets releases constraints on modern resources, providing benefits in several forms. When MISO eventually adopts this practice, the value of the renewable heavy portfolios, as shown for example in the center figure of slide 14, and the opportunity bars of slide 17 will increase. Both wind and solar provide an extremely high quality REG service. Field demonstrations, for example, in CAISO with both wind and solar PV plants,[2] showed that the quality of the REG response from wind and solar PV was measurably superior to thermal generation. Operating expectation (and FERC expectation) is that superior REG performance should result in reduced amounts of REG being procured, saving operating costs for all stakeholders. FERC requires that superior performance be rewarded with accompanying market signals.

Further ERCOT experience with wind plants *always* providing down primary frequency response is partly responsible for a *reduction* in the amount of REG procured by ERCOT as the amount of wind and solar generation has steadily increased. Statistical work in several systems has predicted an increase in the amount of REG needed with higher VER levels, but in practice this is usually not observed. Such behavior will likely impact the analysis here, boosting scores of the renewable heavy portfolios.

[1] These comments were prepared with the assistance of Nicholas W. Miller of HickoryLedge LLC.

[2] CAISO/NREL/FirstSolar "Using Renewables to Operate a Low-Carbon Grid: demonstration of Advanced Reliability Services from a Utility-scale Solar PV Plant"

Blackstart

This is innovative analysis and most welcome. We were confused across the scenario tables for resources (i.e. slide 33, 34, 41), so these comments are not exactly aligned with the scenarios. The deck (slide 40) includes a few up-to-date references for inverter-bases resources providing blackstart. The analysis correctly credits energy storage (assumed to be BESS) equipped with GFM as a credible resource for providing blackstart. But, there appears to be an assumption that the storage (i.e. the battery energy storage portion) of the "solar+storage" resources would not have GFM inverters, and therefore could not be used for blackstart. This appears to result in no credit and correspondingly so for the ES portion of those scenarios with solar+storage. The genesis of this assumption is not clear, but it seems to be at odds with state-of-the-art practice. For example, all of the present tranche of solar+storage projects that have been awarded and are under design now in Hawai'i include *as a contractual requirement of the project* that they have grid-forming inverters on the battery portion.[3] It is HELCO's operational expectation to rely on the grid-forming functionality of the BESS to deliver a wide range of operational benefits. This capability will affect the scoring of these solar+storage projects not only for blackstart, but for short circuit strength, inertial response, and possibly fast regulation. Should NIPSCO go forward with scenarios that include solar+storage, they should expect to demand a high level of functionality from these plants, including state-of-the-art GFM capability. The score of scenarios in the IRP evaluation should reflect that, with the expectation that they will probably improve.

VAR Support

The deck correctly points out that IBRs, including solar PV and wind, have the capability to provide reactive power and to perform voltage regulation *regardless* of whether they are generating (slide 38). BESS can provide voltage regulation regardless of whether it is charging, discharging or idle. Thus, IBR resources *that are specified accordingly* can provide this essential reliability service all the time. In comparison, thermal resources must be committed and running. For fossil generation that is expected to have a relatively low capacity factor, this means that the voltage support will be relatively rare. That benefit is only realized when the generator is running and producing MW, at least at the unit minimum. The exception is for small simple cycle combustion turbines, some types of which can be equipped with a clutch that allows operation of the generator as a synchronous condenser. This feature adds to the capital cost, but can be a significant benefit to systems where the CT is expected to run rarely. LADWP has relatively new units with this feature that are reputed to be run in condenser mode most of the time. Commercial arrangements for this function are non-standard, and the losses associated with this function are non-trivial. The capability is not commercially available on large gas generation, including combined cycle plants. It must be specified at the time of initial design (no retrofits).

[3] For example: Docket 2017-0352, Order # 36604, 10-9-2019. 'Application to HELCO for PPA for Renewable Dispatchable Generation with ENGIE 2020 Project CoHI1' before the Hawai'i PUC.

The reliability metrics on the tables of slides 51, 52 and 53 includes VAR support (line 5 of the tables). That all the options result in the same score seems at odds with the arguably better features of the IBR options. It was not clear if the totals on line 5 are correct.

Ramping

The aggregate dispatchability, and particularly the 1- and 10-minute ramping results seem unnecessarily constrained by traditional views of thermal generation as the primary resource for net load following. For example, the scenarios with energy storage but no thermal generation received quite poor scoring. This seems at odds with the reality that, properly managed, the energy storage elements alone, or the combined resources of solar plus energy storage, can be available for ramping duty every hour of every day. It is a fact that the combined constraints of sunlight and state of charge can constrain capability. Further, ITC constraints that penalize charging the batteries from the grid present an economic (though not physical) constraint that must be respected. But the resources are synchronized and ready *instantly* to provide a very high quality, fast, and finely controllable ramping response all the time. All resources that provide ramping must respect a variety of limits. Surely the fact that, under some conditions, the energy storage resource cannot draw ramping power from the grid is less constraining than the reality that a fossil plant can *never* draw power from the grid. The very high scores for the fossil resources would appear to disregard the reality that these resources must be committed and dispatched to provide ramping services in these time frames. It is the economic expectation that these plants will have relatively low capacity factors, so they will tend to not be running. The plants, and particularly the combined cycle option, are subject to minimum dispatch limitations, minimum start times, minimum run times, and minimum down times, all of which have the potential to negatively impact their ability to provide ramping when needed. This is especially the case for unexpected ramps.

Short Circuit Strength

The technical issues surrounding dropping short current strength are a legitimate concern. It is worth noting that every scenario includes synchronous condensers, which help mitigate the concern. The combined issues of sensitivity of IBRs to low short circuit levels and the potentially adverse impact of low short circuit current *from the IBRs* on protection are real. However, both issues are receiving a great deal of attention from the industry on several fronts. As with the ramping observation, the fossil resources only provide short circuit strength when they are committed. In comparison, grid forming inverters from the new energy storage (either stand-alone or in the solar+storage facilities) can expected to be synchronized all the time. Again, as an example, it is the current reality in Kaua'i and the near future reality on Hawai'i that the system can run and be protected successfully with a single synchronous condenser (Kaua'i today) or an extremely limited number of synchronous machines, relying on their solar+energy storage projects to provide the needed system support. That the end short circuit scoring resulted in such extreme (zeros and ones only) seems at odds with a more nuanced reality.

NIPSCO RESPONSE TO CAC COMMENTS ON RELIABILITY ANALYSIS

NIPSCO Response to Citizens Action Coalition of Indiana, Inc. ("CAC") Comments on NIPSCO's 2021 IRP October 12, 2021 Technical Meeting Submitted on October 20, 2021

<u>Response to Overall Thoughts</u>

Thank you for the timely response to the information presented during the Technical Webinar. NIPSCO appreciates the ongoing, thoughtful engagement with the CAC throughout the IRP Process. NIPSCO considered your feedback when finalizing the preferred plan as well as the report that will be submitted to the Indiana Utility Regulatory Commission ("IURC" or "Commission") by November 15, 2021.

<u>Response to Regulation</u>

Thank you for these comments. NIPSCO agrees that market design changes will impact ancillary services opportunities and that the implementation of an asymmetric regulation market could serve to benefit renewable resources (at least from the perspective of allowing them to monetize ancillary services revenue). While this may be worth evaluating in the future, NIPSCO's sub-hourly ancillary services analysis was primarily targeted towards the relative value of storage versus gas peaker portfolio additions. A fuller portfolio analysis with co-optimized energy and ancillary services dispatch is challenging to perform across time and against multiple scenarios and portfolios, so NIPSCO has taken the approach of performing targeted analyses to assess key resource tradeoffs. However, NIPSCO will continue to monitor Midcontinent Independent System Operator, Inc. ("MISO") market developments and welcomes continued suggestions regarding analytical frameworks that might be useful in future IRPs.

<u>Response to Blackstart</u>

A. The 2030 portfolio mix evaluated in the analysis includes both existing resources and the replacement resource tranches assumed to be operating in the year 2030 that are within NIPSCO's service territory.
B. The reliability analysis and portfolio scoring assumed that stand-alone storage systems will be fitted with grid-forming inverters, while the storage part of solar plus storage resources will be fitted with grid-following inverters. The solar plus storage resources are configured with the storage system operating behind the solar inverter; therefore, it is unlikely for the combined inverter to be grid forming. The CAC's comment is correct that the scoring will be impacted if a

decision is made to require grid-forming inverters also for the storage component of solar plus storage resources. However, this will only impact Portfolios A, D, and G that include 150MW of storage within the 450MW of solar plus storage capacity block.

Response to Volt-Amp Reactive ("VAR") Support

A. NIPSCO agrees with the comments regarding the relative availability of dynamic VARs from inverter-based resources and thermal resources.
B. Given the local nature of reactive power, the "VAR Support" reliability metric is designed to quantify the ability of each portfolio to deliver its dynamic VARs to load centers. The availability of dynamic VARs, however, was not considered in the evaluation due to its dependence on commitment decisions that are beyond the scope of this investigation.

Response to Ramping

A. The ramping component of the dispatchability metric quantified the MWs that each portfolio can provide within one and 10 minutes. Energy storage was assumed to have the capability to provide 100% of its rated MW capacity, while peaker and combined cycle plants were assumed to provide MWs commensurate with their technology.
B. The scores reflect the aggregate ramping capability of all resources within each portfolio. For example, Portfolio H, which does not have peaker or combined cycle plants, was assessed to have the highest ramping capability.
C. NIPSCO will continue to study this topic and take into account CAC's other comments regarding analytical approaches around reliability risk. For example, sub-hourly stochastic analyses of load, renewable output, day ahead forecast error, and other factors might be useful frameworks for assessing ramping needs at various intervals.

Response to Short Circuit Strength

A. NIPSCO appreciates CAC's acknowledgement of the importance of short circuit ratio.
B. All inverters on the market, including grid forming ones, have limited short circuit current capability, and thus are not expected to appreciably increase the short circuit strength of the grid. Compounding this limitation is the uncertain phase angle of the short circuit current (reactive or active) which appears to depend on the inverter control system and thus

manufacturer specifics. Given these limitations and uncertainty, a prudent assumption was made in this study that grid forming inverters can operate successfully at low short circuit ratios and thus assumed to cause no harm. However, they were not assumed to enhance the grid short circuit strength.

C. The “Short Circuit Strength” metric quantified the size of the necessary additions of synchronous condensers in order to maintain an acceptable level of short circuit ratio at each grid-following inverter location in the grid.

Conclusion

We appreciate the CAC’s perspective and thoughtfulness regarding reliability. NIPSCO will continue to monitor MISO market developments and welcomes continued conversation regarding analytical frameworks and reliability assessments that we might consider for future IRPs. As a reminder, all of the Stakeholder Meeting materials are available at nipsco.com/irp. Please contact Alison Becker at abecker@nisource.com to follow up on any of these issues or discuss any additional thoughts.