OFFICE OF UTILITY CONSUMER COUNSELOR ("OUCC")
COMMENTS ON
NORTHERN INDIANA PUBLIC SERVICE COMPANY'S
2018 INTEGRATED RESOURCE PLAN

Demand Side Management

In reviewing Section 5. Demand-Side Resources of the IRP and the in recalling discussions of the All Source RFP, it is apparent NIPSCO considered DSM as an option under the parameters of the RFP. NIPSCO received 90 proposals by technology type in response to its RFP, and one of the 90 proposals was for Demand Response (DR). That DR proposal was for 70 MWs under a one-year Purchase Power Agreement (PPA) under the Midcontinent Independent System Operator (MISO) ICAP and UCAP requirements. In reviewing Figure 4-16 on page 60 of the IRP, the DR proposal was not included in any of the 11 Asset Sale Tranches used in modeling.

NIPSCO updated its Market Potential Study (MPS) for 2018 through 2039. Charles River Associates (CRA) then updated the MPS to extend it through 2048. The residential "incremental annual energy savings" are: 50,974 MWh for 2019, 50,974 MWh for 2020 and 50,918 for 2021 growing to 53,050 MWh in 2048. See NIPSCO IRP at 80-81, Table 5-9. The incremental Commercial and Industrial (C&I) projected savings, which need to be calculated using Table 5-12 at page 85, are 72,000 MWh for 2019, 80,000 for 2020 (152,000-72,000) and 88,000 for 2021 (240,000 – 152,000) with minimal incremental savings for the C&I group of 3,442 MWh in 2048 (1,485,725 – 1,482,283).

CRA also projected DR impacts on energy savings through 2048. The projected total Energy Efficiency (EE) cumulative savings was 1,610,063 MWhs through 2048 and 431 MWs through 2048

The projected energy savings included in the IRP available for selection are just slightly different from what was included in the 2019 to 2021 Plan approved by the Commission. NIPSCO modeled three bundles of DSM measures based on the updated MPS and Action Plan and ultimately accepted two of them: Bundle 1 represented measures with a utility incentive cost less than $.01 per lifetime kWh saved. Bundle 2 represented measures with a utility incentive cost ranging from $.011 to $.05 per lifetime kWh saved.

The bundles modeled were arranged according to cost, and all of the resources in the first two bundles were selected by the optimization model across all portfolios. The third bundle, with incentive costs ranging $.051 and above, representing a cumulative projected savings of 174,572 MWh through 2048, was not accepted. Bundle 3's projected savings in comparison to the cumulative savings projected for Bundle 1 and Bundle 2 is 8.47% of the cumulative total projected savings of 2,060,768. The DR included in the bundles were projected at 330.3 MWs for Bundle 1, for 57.8 MWs for Bundle 2, and 45.2 MWs for Bundle 3. The Bundle 3 cumulative projected MWs are 45.2 or 11.65% of the total three bundles modeled.

NIPSCO's Oversight Board spent a considerable amount of time addressing the efficacy of the savings estimates in the 2019 to 2021 DSM Plan and is comfortable the projected savings levels included in the 2019 to 2021 Plan are reasonably achievable. The OUCC is comfortable that savings projected through the first half of the period can be realized and will not materially impact any generation assumptions. While the projections through 2048 were prepared in accordance with typical forecasting techniques and reliability the OUCC is not as confident in NIPSCO's ability to realize the long-term projected EE and DR savings due in part to compounding uncertainty beyond the earlier years.

Economic Modeling

NIPSCO used Aurora, a standard economic modeling software, and contracted with CRA, a consulting firm capable of performing the modeling. This supports the reasonableness of the economic modeling performed as part of this IRP process. That said, the results represented in the IRP report are those of NIPSCO. While NIPSCO offered the OUCC an opportunity to provide feedback, and the OUCC did so to the extent practicable, the inputs selected and the choices made in the modeling were NIPSCO's. The OUCC has not performed an in-depth review of model run details as might be done in a Certificate of Public Convenience and Necessity (CPCN) proceeding where time and resources can be devoted to that specific task.

NIPSCO's use of a two-step approach to its economic modeling—first a retirement analysis and then a replacement analysis—is theoretically suboptimal from the standpoint that retirement decisions should be made simultaneously with choices among options for replacing the retired assets. However, the OUCC does not believe that this limitation is necessarily fatal to NIPSCO's IRP analysis in this instance.

NIPSCO issued an all-source request for proposal (RFP) seeking proposals for its expected capacity need in 2023. NIPSCO's use of an RFP as part of its IRP which, given NIPSCO's expected needs, was especially useful in this situation. This produced a robust number of responses. NIPSCO's use of these RFP responses are addressed in more detail elsewhere in these comments.

Within NIPSCO's modeling framework, the retirement path that it chose ("Retirement Portfolio 6") was identified[1] in the "base" scenario as having a 3% higher Net Present Value Revenue Requirement (NPVRR) than the lowest cost retirement timeline, which would have all coal units retired in 2023. In contrast, NIPSCO calculated that the NPVRR of retaining all coal units was 40% higher than that lowest cost portfolio. All other things equal, the OUCC would prefer that the lowest cost portfolio be selected. When other factors are considered, it is not always unreasonable to select a higher cost portfolio. Additionally, this result was supported under the three other scenarios modeled and in the stochastic analysis conducted. NIPSCO's "Portfolio Scorecard,"[2] while more subjective, was similarly supportive of NIPSCO's chosen retirement path. While there could be some undiscovered mistakes and/or residual concerns about modeling, the OUCC believes that NIPSCO's decision to retire its coal units as represented in Retirement Portfolio 6 is not necessarily unreasonable. It is always possible that the discovery of new, material information could impact the ultimate reasonableness of this decision. As actual filings are made with the IURC and additional case-specific details emerge, the OUCC's position will likely continue to evolve.

NIPSCO's replacement analysis selected 1300MW of renewables and 50 MW of MISO Capacity purchases. This portfolio had the lowest NPVRR among the six alternative portfolios modeled

[1] Page 151 of IRP Report.
[2] Page 155 of IRP Report.

under the base scenario, and among the lowest NPVRRs under the other three scenarios.[3] This chosen path would put NIPSCO among the utilities nationally with the highest proportion of load served by renewable resources. Given the essential nature of electric utility service, reliability is of utmost importance and the OUCC raises concerns elsewhere in these comments about the practical ability to serve load with the high level of intermittent resources envisioned by NIPSCO. The OUCC also has concerns that MISO may change its rules pertaining to the valuing and treatment of intermittent resources if other utilities plan their systems in a manner similar to how NIPSCO has in this IRP.

OUCC was disappointed NIPSCO did not include gas conversion technology for coal-fired boilers as part of its all-source RFP. Rather, NIPSCO performed this analysis outside its all-source RFP. NIPSCO presented the OUCC with <u>*iterative*</u> study results after the OUCC raised costs and technology adoption issues.

Thus, the OUCC has some concerns, but given the relatively short timeframes needed for building renewable and gas-fired capacity, mid-course corrections can be made if warranted.

<u>System Operations Concerns</u>

The IRP process concluded without discussion concerning the physical practicality of serving NIPSCO load absent most of its current thermal generating resources. Using UCAP numbers from the IRP, approximately 48% of generating capacity will be from intermittent resources in 2023.

[3] Page 165 of IRP Report.

After Michigan City 12 is retired, the percentage jumps to 61%. Using nameplate capacity, the initial percentage climbs to roughly 80%.

This high penetration of intermittent generating resources implies there will be a considerable amount of imported and exported power, depending on weather, seasons and the availability and price of external resources such as MISO. As renewables increase, transmission upgrades may also be required, costs which will likely ultimately be borne by ratepayers. The modeling conducted by NIPSCO shows a net amount of future power purchases from MISO and is similar to what NIPSCO sees in today's market. For economic reasons, NIPSCO currently supplies only 80% of its energy needs from self-owned generation. Due to the high cost of operating Schahfer and Michigan City, these units are sometimes not selected by MISO to run. Because today's market contains excess capacity and relatively inexpensive energy based primarily on thermal generation, NIPSCO can relatively easily acquire its other energy needs.

In contrast, future NIPSCO market needs will likely be based upon physical needs to augment the intermittent generation. While it is certain there will be periods when the intermittent generators produce far more than NIPSCO's load, there will also be extended periods of low output. The modeling assumes this overproduction is fully absorbed by the MISO market and purchases made to supplement intermittent or low production are always available. Feast and famine cycles should be expected. Although the modeled net purchases are roughly the same as today's amount, the high variability will impose very different requirements on the system.

NIPSCO plans to rebuild several transmission circuits to facilitate the Schahfer station retirement. There was no explanation concerning the nature of the upgrades, why they were chosen, or whether additional transmission upgrades would be necessary. NIPSCO's plan also anticipates the addition of a 240 MVA Reactive Source due to the Schahfer plant retirement. The IRP does not identify whether either the upgrade costs or the Reactive Source costs are included in the IRP analyses and what those amounts will be. Sugar Creek, the remaining gas-fired combined cycle generator, does not connect directly to the NIPSCO system and consequently does not supply VAR support.

NIPSCO has fixed the capacity credit for solar PV resources at the current MISO accreditation of 50% of nameplate capacity for the life of the assets. In a recent MISO study,[4] it is concluded the amount of capacity credit such resources will receive should decline with the increased penetration of those types of resources. The amount of solar PV NIPSCO plans may push the expected capacity credit down the curve shown on Figure 2 of the referenced report. While acknowledging today's market constructs may change based upon future MISO evaluation of Effective Load Carrying Capability[5], the IRP states only that NIPSCO will monitor changes. NIPSCO has not attempted to account for a potentially significant increase in the amount and cost of additional solar capacity, which becomes less valuable with every MW added.

Environmental

As part of the replacement assessment, NIPSCO evaluated environmental risk concentrating on the potential for a carbon policy, which included a price charged for carbon emissions. (*See*

[4] https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v6301579.pdf
[5] NIPSCO 2018 IRP, page 5

NIPSCO IRP Sec. 8.2.3, page 117.) NIPSCO used the Clean Power Plan, passed during the Obama Administration, as a map to what Carbon Emission regulation may look like in the future. NIPSCO rightfully admits carbon reduction regulations have been attempted in the past, but there has yet to be a fully implemented regulation for carbon emissions in the state of Indiana or by the United States Federal Government. (*See* NIPSCO IRP Sec. 8.2.3 page 117.) Although it is reasonable for NIPSCO to consider potential carbon emission regulation, NIPSCO should also have evaluated stricter regulations regarding human health, air, land, water, and endangered species.[6]

Although NIPSCO's replacement assessment environmental risk analysis discussed above was narrow in approach, during NIPSCO's retirement assessment the company ultimately made an effort to evaluate all environmental impacts. (*See* NIPSCO IRP Sec. 9.1, page 145.) Of the regulations burdening coal plants, the greatest was the effluent limitations guidelines and standards for steam electric power plants ("ELG Rule"). The ELG rule protects water resources. The ELG rule requires coal plants to mechanically treat, biochemically treat, or eliminate liquid discharge of contaminants. Making these upgrades can be very costly.

NIPSCO has selected a preferred portfolio which includes many renewable resources, mostly wind and solar. While these resources have many environmental benefits (emission free, local, not dependent on imported fossil fuels), they also come with environmental impacts. Solar and Wind Energy can also be very land intensive, requiring many acres of land as seen below[7]:

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[6]Some examples of environmental regulations (do not involve carbon emissions pricing) affecting the various of types of energy generation include: (1) Endangered Species Act of 1973, 16 U.S.C. ch. 35 § 1531 et seq (2) Coal Combustion residuals rule of 2015, 40 CFR Parts 257 and 261 and (3) ELG rule of 2015 40 CFR Part 423.

[7] Land Use of U.S. Electricity Production, STRATA, June 2017, https://www.strata.org/pdf/2017/footprints-full.pdf.)

Chart 1: Land Use by Electricity Source in Acres/MW Produced

Electricity Source	Acres per Megawatt Produced
Coal	12.21
Natural Gas	12.41
Nuclear	12.71
Solar	43.50
Wind	70.64
Hydro	315.22

Wind energy can affect endangered species including the bald eagle, the northern long ear bat, and the Indiana bat. Before a wind project can be constructed the developer must get permission from U.S. Fisheries and Wildlife to minimize the effects to these endangered specifies.