NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC'S RESPONSE TO THE DRAFT DIRECTOR'S REPORT FOR THE NIPSCO 2021 INTEGRATED RESOURCE PLAN

Introduction

NIPSCO appreciates the Director's feedback as provided through the Draft Report. The Director's comments regarding the continued improvements NIPSCO made in the 2021 report were appreciated. The NIPSCO team invested a great deal of time and effort into building on the 2018 IRP analysis, and it is welcomed feedback noting that the improvements addressed unprecedented resource changes in an environment of extreme uncertainty regarding government policy, commodity prices, and technology. As the Director noted several times, NIPSCO continues to look for ways to improve its process.

NIPSCO is committed to maintaining and building upon those improvements going forward. The NIPSCO team also recognizes that the Integrated Resource Plan ("IRP") process is always evolving. NIPSCO is continuously looking for ways to enhance data quality and quantity, its load forecasting process, and how the impacts of paradigm shifts in the use of electricity in the future are analyzed. NIPSCO will take both the Director's comments and the comments provided by the stakeholders into account when preparing its next IRP. The comments included in this document are meant to provide clarity where necessary on NIPSCO's IRP based on comments in the Draft Report. Failure on the part of NIPSCO to address a specific recommendation made by the Director is not a rejection of that recommendation by NIPSCO.

NIPSCO's Responses

Load Forecasting

Concerning the Director's question regarding load factors (page 7), the load factors shown in Figure 3-6 were assumed to remain constant over time in the core econometric load forecasting analysis. Please note, however, that several load elements that impact load factor trends were evaluated outside of the core econometric analysis. These include demand side management/energy efficiency ("DSM/EE"), electric vehicle ("EV") penetration, and customer-owned distributed energy resource penetration. The load factor impacts from these changes over time were incorporated in the net load forecast and the IRP analysis.

The Director also asked about the projection of the number of households (page 7) "Where do the projected values for number of households (Xij) come from? Does Moody's project that? (See page 27, equation 3-1)"). The answer is yes, Moody's projects the number of households at the state level. NIPSCO used the Moody's projection in its econometric forecast.

Also on page 7, the Director asked about Table 3-3 ("Do the numbers in Table 3-3 represent only the portions of counties served by NIPSCO or the entire county? This could be significant in a county like St. Joseph, where much of the county is served by another utility. If the numbers represent the entire county, were the numbers adjusted in any way prior to projecting the growth and being added to the load forecast? (See pages 37-38)"). The numbers in Table 3-3 represent data for the entire county. It is true that for certain counties, many of the vehicles could be in other service territories, but even if assuming all vehicles are in NIPSCO's service territory, the historical totals only amount to about 0.2% of total light duty vehicle stock. Given that NIPSCO's EV scenarios were based on the Midcontinent Independent System Operator, Inc. ("MISO") Transmission Expansion Plan penetration levels, the historical data was used only as a guide for a reasonable starting point to trend into the MISO penetration levels. As EV counts increase, NIPSCO will look to refine its data gathering processes to more precisely track vehicles within the service territory.

Regarding the Director's comment on EV charging profiles on page 7 ("It is unclear whether separate weekday and weekend EV charging profiles are used. Figures 3-9 and 3-10 show different profiles that are apparently based on NIPSCO data and DOE data, respectively. Figure 3-11 only shows single profiles for low and high penetration and the text is not clear."), separate weekday and weekend profiles were used in the analysis. For modeling purposes, a full 168-hour weekly shape was used, with the weekday shape for Monday through Friday and the weekend shape for Saturday and Sunday. Figure 3-11 was used to illustrate a sample weekday EV load shape relative to the hourly power price shape for each season. NIPSCO will endeavor to make this clearer in future IRPs.

The Director also expressed concern related to the industrial load forecasting methodology and requested more discussion of the change in forecasting with the implementation of Rate 831 (page 7). NIPSCO conducted additional analysis regarding industrial load growth as part of the load forecasting process, including econometric analysis of the small industrial group and customer-level assessments of its largest class of industrial users. For small industrial customers, NIPSCO developed forecasts based on new econometric variables such as manufacturing employment levels and assessed class-level monthly load factors for the first time. For the largest industrial customers, NIPSCO evaluated individual customer data and incorporated expected migrations to Rate 831 both in the Reference Case and as part of a low load case in the Status Quo Extended scenario. NIPSCO agrees that the underlying analysis associated with large industrial customer forecasts could have been more clearly described in its written report, and NIPSCO will take this concern into account when preparing subsequent IRPs.

Demand Side Resources

On page 9, the Director said, "The Director appreciates the effort to evaluate the usefulness of a limited form of dynamic rates in the IRP but believes this is an area deserving of greater attention given the range of load uncertainty and increasing dependence on intermittent resources. Also, more attention should be paid to the interaction between EE and DR with each other." NIPSCO agrees that dynamic rates warrant additional, future analysis given current uncertainties and increasing dependance on intermittent resources. For the 2021 IRP, the Company noted that the advanced metering infrastructure ("AMI") required to facilitate dynamic rates was not expected until 2030. Dynamic rates will likely be afforded increased attention in future studies as the rollout of advanced metering infrastructure is underway.[1] In addition, the market potential study ("MPS") considered the interaction of EE and DR regarding smart thermostats and direct load control of these devices. The DR Analysis considered the forecasted adoption levels of smart thermostats (from the energy efficiency MPS) on the future potential for direct load control. That same modeling framework will work well with other devices as more and more equipment becomes connected and controllable.

The Director also requested additional information regarding the EE program evaluation results and net to gross ("NTG") ratios to the MPS estimates (page 10). All existing program measures included in the net realistic achievable potential leveraged

[1] NIPSCO's AMI program was approved by the Commission in Cause No. 45557 (NIPSCO's current Transmission, Distribution, and Storage System Improvement Charge Plan) on December 28, 2021, which was subsequent to NIPSCO's filing of the 2021 IRP. The original demand response analysis was underway prior to NIPSCO's filing in Cause No. 45557, and the deployment date of 2030 was deemed appropriate at the time because AMI had not yet been approved by the Commission. As described in that Cause, NIPSCO currently expects to have full AMI deployment in its electric service territory by 2026.

the latest available program evaluation results for the basis of the assumed NTG ratio. These results are still highly relevant because the overall portfolio NTG ratio has been consistent each of the last five years. The overall portfolio-level NTG ratio in 2019 was 78%, and the average portfolio-level NTG ratio for the four years on either side of 2019 (2017-2018, and 2020-2021) is also 78%. This indicates, despite fluctuations in gross savings over time, the NTG ratio for NIPSCO portfolios has been remarkably consistent. For this reason, the estimates used in the study were and remain the best available data. Hopefully this provides greater clarity on how NIPSCO applied the evaluation results.

Also on page 10, the Director noted that additional details regarding the application of the three adjustments applied to the potential savings would be helpful ("NIPSCO affirms that the 'income-qualified achievable savings were also scaled accordingly' as part of the adjustments applied to the MPS's realistic achievable energy efficiency potential savings. Also, another three adjustments were applied to these potential savings. More details regarding the technical parameters used to conduct these adjustments would clarify and facilitate the understanding of this process."). The four adjustments to the MPS' realistic achievable potential are described on pages 133 and 134 of the IRP.

The first adjustment converted the energy efficiency from gross savings to net savings. This was done by applying a measure-level NTG ratio multiplier, using the 2019 program evaluation results, which translates the gross measure-level savings to net measure-level savings. As noted in the question, the second adjustment aligned the level of income-qualified potential, identified in the realistic achievable potential, with levels achieved historically by NIPSCO. The third adjustment was to provide the achievable potential savings at the generator level. This involved simply multiplying the at-the-meter savings in the MPS by a line loss factor ("LLF") to translate these savings into at-the-generator savings. As noted on page 122 of the IRP (footnote 71), the peak residential LLF used in the analysis was 4.11%, and the peak commercial and industrial LLF were 3.76% and 2.41%, respectively. The fourth and final adjustment was to re-screen the cost-effectiveness under an alternative cost of generation. The base case avoided cost of generation is set to $129 per kW-year, and the alternative avoided cost of generation is set to $80 per kW-year. NIPSCO will seek to provide additional description regarding any needed DSM adjustments in future IRPs.

Finally, the Director questioned the drop in projected EE savings from the 2018 IRP (page 10, "What drives the drop from 1,137,101 MWh (Table 5-17, Page 90) in the total cumulative annual savings of all the EE bundles used in 2018 IRP for 2027 to only

387,917 MWh (Table 5-14, Page 135) in the bundles used in the most recent 2021 IRP for the same year? This is significant drop in the estimated EE savings used as resource options in the optimization model from the previous IRP to the current.”). There are two primary drivers in the differences noted. First, the 2018 IRP data referenced includes nine years of cumulative annual savings, whereas the 2021 IRP data referenced only includes four years of cumulative annual savings. This accounts for approximately 50% of the noted difference in savings. The remaining difference is a significant decrease in savings opportunities in the lighting end-use for both the residential and commercial/industrial sector in the 2021 IRP compared to the 2018 IRP. In the residential sector, light emitting diode lighting opportunities were significantly reduced in the 2021 IRP recognizing that much of the screw-based market has been transformed. Similarly, in the commercial sector, lighting opportunities were reduced based on updated market saturation estimates and a declining annual forecast for lighting savings (versus the increasing forecast for lighting savings used in the 2018 IRP).

Stakeholder Comments

As NIPSCO noted in its response to the comments from its stakeholders, it appreciates their feedback and will incorporate a number of their recommendations into future IRPs. NIPSCO also appreciates the Director’s comments on the stakeholders’ submissions and will adjust as appropriate.

Conclusion

With these clarifications, NIPSCO has intended to address, in at least some part, the concerns or uncertainty expressed in the Director’s Draft Report. NIPSCO is always available to meet with the Commission staff for further discussion on its IRP. In fact, as part of its public advisory process, NIPSCO established an ongoing communications process with all stakeholders. NIPSCO appreciated the participation of its stakeholder group, including the Indiana Utility Regulatory Commission and staff, in its IRP public advisory process. NIPSCO will look to incorporate the lessons learned from the 2021 process into its next public advisory process and IRP. It is NIPSCO’s hope that these responses will help provide further clarity regarding its 2021 IRP and serve as a starting point for further informal discussions to support its next IRP.