IURC
JOINT PETITIONER'S
EXHIBIT NO. 4
5-22-19
DATE REPORTER

VERIFIED DIRECT TESTIMONY OF PATRICK N. AUGUSTINE

Q1. Please state your name, professional position, and business address.

A1. My name is Patrick N. Augustine. I am a Principal in Charles River Associates' Energy Practice. My business address is 1201 F Street, NW, Washington, DC 20004.

Q2. On whose behalf are you submitting this direct testimony?

A2. I am submitting this testimony on behalf of Northern Indiana Public Service Company LLC ("NIPSCO").

Q3. Please briefly describe your educational and business experience.

A3. I received a Bachelor of Arts degree from Harvard University and received a Master of Environmental Management degree from the Nicholas School of the Environment at Duke University. I have been employed by Charles River Associates ("CRA") for three years and have worked in the energy consulting industry for over twelve years. Prior to joining CRA, I worked at Pace Global Energy Services, now a Siemens business, for over nine years, performing the roles of analyst, project manager, and director. At CRA, in my role as Principal I oversee the maintenance of the firm's power market modeling tools and processes, I manage consulting assignments in the power and utilities sectors, and I supervise junior staff in performing market, policy, and strategic analyses for our clients.

Q4. Please describe CRA and the work you perform in more detail.

A4. CRA is a consulting firm that offers economic, financial, and strategic expertise to support our clients in business decisions, regulatory and litigation proceedings, and market and policy analysis. My professional experience within CRA's energy practice has focused on power market analysis and utility resource planning work to support project developers, electric utilities, investors, and lenders in energy market forecasting, power asset valuation, and utility portfolio planning. This work involves energy market research and analysis and the use of market models, particularly those that simulate the competitive electric power markets and those used for electric utility portfolio dispatch analysis and cost accounting.

Q5. Have you previously testified before this or any other regulatory commission?

A5. Yes. I previously provided testimony before the Indiana Utility Regulatory Commission in NIPSCO's currently pending electric rate case in Cause No. 45159. I have also provided testimony and appeared before the Kentucky Public Service Commission with regard to an application for approval of an environmental compliance plan and associated cost recovery in Case No. 2012-00063; on behalf of a power generating asset owner before the Michigan Public Service Commission in the course of a Certificate of Need proceeding in Case No. U-17429; and before the Public Utilities Commission of Ohio with regard to the power market forecasts used in a distribution modernization plan in Case No. 18-1875-EL-GRD.

Q6. What is the purpose of your direct testimony in this proceeding?

A6. The purpose of my testimony is to discuss the preferred portfolio from NIPSCO's Integrated Resource Plan submitted October 31, 2018 (the "2018 IRP") and how the assumptions associated with the new wind resource options modeled in the 2018 IRP compare with the cost of NIPSCO's investment in a wind generation joint venture, RoseWater Wind Generation, LLC (the "Joint Venture").

Q7. Are you sponsoring any attachments to your direct testimony?

A7. Yes. I am sponsoring the public version of NIPSCO's 2018 IRP, attached hereto as <u>Attachment 4-A</u>. NIPSCO hired CRA to perform the analysis and modeling for the IRP, and the portfolio analysis produced in Section 9 of the IRP was prepared by me or under my direction and supervision.

Q8. Please provide an overview of NIPSCO's preferred portfolio from the 2018 IRP and how it was developed.

A8. NIPSCO's preferred portfolio retires all four coal units at the R.M. Schahfer

Generating Station ("Schahfer") in 2023 and retires the Michigan City Generating Station ("Michigan City") coal plant in 2028. The preferred portfolio includes the following capacity replacements over time: 125 megawatts ("MW") of energy efficiency and demand side management peak load savings by 2023, growing to 370 MW by 2038; approximately 1,100 MW of installed capacity ("ICAP")[1] wind representing 157 MW of unforced capacity ("UCAP")[2] entering into service in 2020 and 2021; approximately 2,100 MW of ICAP solar representing about 1,050 MW of UCAP in 2023, along with additional generic solar over the long-term; and 175 MW of ICAP solar plus storage capacity representing approximately 90 MW of UCAP in 2023. Section 9.3 of the 2018 IRP provides additional detail associated with the preferred replacement portfolio.

The plan was developed through substantial quantitative and qualitative analysis, including the use of an all-source request for proposal ("All-Source RFP") solicitation (discussed in greater detail by Witness Lee) to identify the most

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[1] Installed capacity or ICAP represents the nameplate capacity of a resource and the maximum amount of output that can be produced at any given time.

[2] Unforced capacity or UCAP represents the expected capacity available during the system peak. For renewable resources, MISO relies on historical operational data during peak hours or generic planning numbers based on a system-wide effective load carrying capability analysis. The 2018 IRP developed UCAP numbers based on bidder responses to the All-Source RFP (where available) and generic estimates of approximately 15% of ICAP for wind resources and 50% of ICAP for solar resources.

relevant types of resources available in the market, along with their associated costs. Within the 2018 IRP, NIPSCO performed retirement and replacement assessments using robust scenario and risk-based (stochastic) analyses and scored the various portfolio alternatives against a number of cost, risk, environmental, and reliability metrics to arrive at the preferred portfolio. NIPSCO also evaluated the impact each of the retirement and replacement alternatives would have on local communities and NIPSCO's employees.

Q9. Please provide an overview of the 2018 IRP's Short Term Action Plan as it relates to the replacement resources in the preferred portfolio.

A9. Part of the Short Term Action Plan, which is outlined in detail in Section 9.4 of the 2018 IRP, relates to selecting and acquiring replacement projects to fill the capacity gap that develops as a result of the planned retirements in 2023 in the preferred portfolio. In the Short Term Action Plan, NIPSCO identified a phased-in approach to selecting and acquiring these replacement resources. The plan calls for initially prioritizing replacement resources with expiring or declining tax credits, followed by another All-Source RFP to acquire resources to fill the remainder of the 2023 supply requirement. The prioritized replacement resources are wind projects looking to qualify for the federal production tax credit ("PTC"), which is expiring over the next few years, as described in more detail by Witness Campbell. The prioritization of these resources in the Short Term Action Plan is based on the 2018 IRP's finding that procuring wind resources that qualify for the PTC saves customers nearly $500 million on a net present value basis compared to a portfolio that relies solely on solar plus storage resources to fill the 2023 capacity gap.

Q10. What specific wind resources were included in NIPSCO's preferred portfolio?

A10. The preferred portfolio included two wind resource additions. The first was an asset acquisition of 600 MW of ICAP (90 MW of UCAP) in 2020. The second was a power purchase agreement ("PPA") of 501 MW of ICAP (67 MW of UCAP) in 2021.

Q11. How did NIPSCO use the All-Source RFP to determine the cost and operational performance assumptions of wind resources in its IRP?

A11. As part of the IRP input development process, CRA organized the various bids received in the All-Source RFP into groupings or tranches according to technology, whether the bid was for a PPA or an asset acquisition, the bid's commitment duration, and the bid's costs and operational characteristics. This approach allowed for the efficient development of planning-level assumptions that could be transparently shared with stakeholders and deployed in the IRP models. This process resulted in the development of distinct wind sale and PPA tranches, which were eligible to be selected in the portfolio analysis in part or as a whole block of capacity. Section 4-10 of the 2018 IRP describes this process in more detail.

Q12. What specific assumptions were used for the wind tranches that were selected in the preferred plan in the 2018 IRP?

A12. The asset acquisition of 600 MW of ICAP (90 MW of UCAP) was assumed to enter into service in the middle of 2020, with an acquisition price of $1,442/kilowatt ("kW") (in 2020 dollars) and a capacity factor of approximately 41%. Fixed operations and maintenance ("FOM") costs were assumed to be approximately $42/kW-yr (in 2017 dollars), with ongoing capital expenditures of $11/kW-yr (in 2017 dollars). Property taxes were assumed to be 2.16% of the net book value of the plant over time. The PPA of 501 MW of ICAP (67 MW of UCAP) was assumed to enter into service in the middle of 2021 with a twenty-year contract duration, a fixed nominal PPA price of $25.54/MWh, and a capacity factor of approximately 42%.

Q13. Are you able to compare the total cost of the Joint Venture with the total costs of these tranche-level inputs used in the 2018 IRP modeling?

A13. Yes. I made such a comparison through the development of a levelized cost of electricity ("LCOE") calculation for each of the 2018 IRP resource options and the 102.6 MW Joint Venture. The LCOE develops a levelized, all-in cost of a given resource option over a pre-defined analysis period on a per MWh basis. This approach allows for a direct comparison of the costs of the different wind projects over an extended time frame by distilling all key parameters related to costs and operational performance into a single dollar per MWh number.

Q14. Please explain the inputs that are required to perform an LCOE calculation.

A14. For an owned resource, the following input parameters are included: the acquisition cost of the project in dollars per kW, adjusted for the contribution of a tax equity partner that can realize the benefits of federal tax incentives; NIPSCO's weighted average cost of capital ("WACC") and capital structure projected as of December 31, 2019; the expected FOM costs and ongoing capital expenditures over the thirty-year planning horizon; the expected property taxes over time; cash payments to the tax equity partner; and the expected generation output in MWh for the resource over time.

For a PPA resource, the following input parameters are included: the PPA price in dollars per MWh over the term of the contract; the expected generation output in MWh for the resource over time; and the expected market cost to replace the generation output after the expiration of the PPA contract term if it falls within the thirty-year planning horizon. The expected difference between the nodal price at the project and NIPSCO's load node is an input for both owned and PPA resources in order to quantify the expected congestion risk over time, as discussed further by Witness Campbell.

Q15. What LCOE values did you calculate for the two wind resource tranches incorporated in the 2018 IRP's preferred portfolio?

A15. The thirty-year LCOE of the 2020 wind acquisition was calculated to be \$38.99/MWh, based on the acquisition price, capacity factor, FOM costs, ongoing capital expenditures, and property taxes summarized above and an assumed thirty-year project life. The thirty-year LCOE of the 2021 wind PPA was calculated to be \$32.63/MWh based on the twenty-year PPA price summarized above plus an additional ten years of market-based energy costs to evaluate the total cost of energy over the full planning horizon.

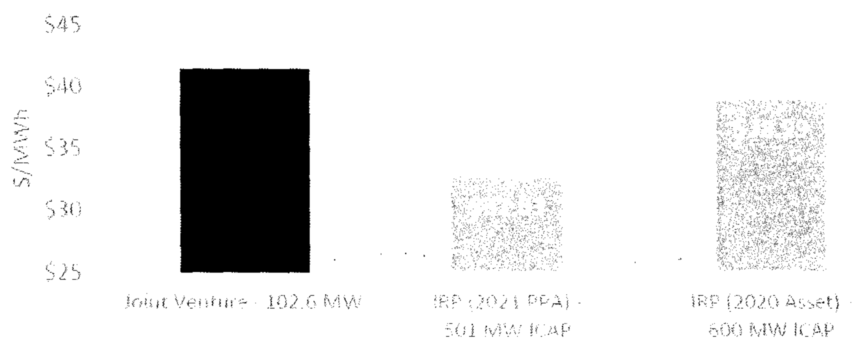
Q16. What LCOE values did you calculate for the Joint Venture?

A16. The thirty-year LCOE of the Joint Venture was calculated to be $[redacted]. This is based on an acquisition cost of $[redacted], a capacity factor of [redacted], and a thirty-year project life.

Q17. How do the LCOE values for the wind resource tranches incorporated in the 2018 IRP's preferred portfolio compare with the LCOE of the Joint Venture?

A17. Figure 1 illustrates that the LCOE of the Joint Venture is above the LCOE of the PPA tranche by [redacted] and above the LCOE of the owned resource tranche by $[redacted].

Figure 1. Levelized cost of wind energy



Q18. What is the expected impact of the $[redacted] premium versus the IRP owned resource tranche on a net present value of revenue requirements (NPVRR) basis?

A18. For all of the expected MWh generated by the Joint Venture wind project over a thirty year time period, an $[redacted] premium would equate to approximately $[redacted] in NPRVRR for NIPSCO. This represents less than [redacted] of the total projected $500 million in customer savings that can be realized through the addition of PTC-eligible wind to NIPSCO's portfolio.

Q19. How does the relief requested in this proceeding support the conclusions of the 2018 IRP and its Short Term Action Plan?

A19. The operational and cost characteristics of the Joint Venture are consistent with the assumptions for new wind resources used in the 2018 IRP, which developed a preferred portfolio with approximately 1,100 MW (ICAP) of wind additions in the 2020-2021 time period. On an LCOE basis, the cost of the Joint Venture is slightly higher than the comparable owned resource tranche in the 2018 IRP, although this difference only amounts to an expected increase in the NPVRR of approximately [redacted], which is far less than the savings projected for NIPSCO's customers in the 2018 IRP's preferred portfolio. Furthermore, the generation-weighted average LCOE of the three wind projects currently being pursued by NIPSCO ([redacted]) is lower than the generation-weighted average of the two wind tranches used in the 2018 IRP ($36.07/MWh). The Short Term Action Plan called for prioritizing the acquisition of such wind projects prior to the phase-out of the PTC based on the finding that this produces substantial savings for NIPSCO's customers. Thus, the addition of the Joint Venture to NIPSCO's portfolio in 2020 is fully supportive of and consistent with the conclusions of the 2018 IRP and the recommended Short Term Action Plan.

Q20. Does this conclude your prefiled direct testimony?

A20. Yes.

VERIFICATION

I, Patrick N. Augustine, Principal at Charles River Associates, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Patrick N. Augustine

Dated: February 1, 2019